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EVALUATE FOAMS TO IMPROVE OIL RECOVERY FROM HEAVY OIL RESERVOIRS

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Final Report

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Work on the project was conducted under the auspices
of the Canada Centre for Mineral and Energy Technology,
Energy, Mines and Resources Canada

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DISCLAIMER

This report was prepared as an account of work sponsored by Texaco Canada Resources (TCR) and the Canada Centre for Mineral and Energy Technology (CANMET) and carried out at the Petroleum Recovery Institute (PRI). Every possible effort was made to ensure that the work conforms to accepted scientific practice. However, neither the TCR, nor the CANMET, nor the PRI, nor any of their employees, makes any warranty, express or implied or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trade mark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the TCR, the PRI or the CANMET. The views and opinions of authors expressed herein do not necessarily state or reflect those of the TCR, the PRI or the CANMET.

SUMMARY

This experimental investigation was carried out to develop a foam treatment for possible field application in a steam flood operation. The experimental work was done at the Petroleum Recovery Institute under a cost shared program funded jointly by Texaco Canada Resources (presently merged with Esso esources Canada) and Canada Centre for Mineral and Energy Technology. The aims of the study were; (1) to evaluate several available surfactants for selecting the most promising candidate, (2) to provide data on effect of several process parameters for the selected surfactant.

Six different surfactants, representing a cross section of temperature stable surfactants currently in the market, were evaluated in Ottawa sand cores. The increase in pressure drop across the core resulting from injection of the foaming surfactant with steam into the core containing steam flood residual oil was measured. All surfactants except one caused large increases in the pressure drop. The main distinguishing features were the time required to achieve the high differential pressure and the minimum flow rate required to sustain the foam. In addition the extent of surfactant losses due to adsorption and thermal degradation in the field were also considered. These were not measured in this study but information from other sources was used. Chevron Chaser SD-1000 was selected as the most promising candidate based on the experimental results, available information on adsorption and thermal stability, surfactant cost and availability.

The foam properties of Chevron Chaser SD-1000 were measured in Ottawa sand cores and in preserved reservoir cores. The effects of concentration, flow rates, steam quality and non-condensable gas were examined.

A proposal for a field trial, based on this research, was developed.

SOMMAIRE

Cette recherche expérimentale a été fait pour constrire un traitement de mousse pour application du terrain dans un operation du flot de vapeur. Les expériences ont été fait par le Petroleum Recovery Institute, et les frais ont été payés tous les deux par Texaco Canada Resources (maintenant amalgamé avec Esso Resources Canada) et Le Centre Canadien pour le Technologie des Mineraux et de l'Energie. Les buts de l'étude étaient: (1) évaluer quelques surfactants disponibles, et déterminer le meilleur candidat de ceux-ci, (2) donner les faits sur l'effet de quelques conditions du processus pour le candidat determiné.

Six surfactants différents, une vraie population représentative des surfactants (de stabilité thermale) maintenant utilisé par l'industrie, ont été évalué dans une carotte de sable d'Ottawa. On measure l'augmentation de baisse de pression à travers la carotte (avec un résidue d'huile après le flot de vapeur) qui forme à cause de l'injection, avec le vapeur, du surfactant en moussant. Tous les surfactants sauf un, ont causé les grandes augmentations de baisse de pression. Les traits distingués principaux étaient le temps nécessaire pour établir la haute pression différentiale et le débit minimum, nécessaire pour soutenir la mousse. Aussi, la quantité des pertes à cause de l'adsorption et le dégradation thermique au terrain ont été considerè au moyens indirects en utilisation des données des autres études. On a determiné que "Chevron Chaser SD-1000" était le meilleur candidat établi sur les résultats expérimentals, renseignements disponibles sur l'adsorption et stabilité thermique, et le frais et disponibilité des surfactants.

Les traits moussant de "Chevron Chaser SD-1000" ont été measurés avec les carottes de sable d'Ottawa et avec les carottes preservées de réservoir. On a examiné les effets de concentration, débits, qualitée de vapeur, et du gaz non-condensable.

Un proposition pour un application du terrain, établi sur cette recherche, a été développé.

CONCLUSIONS:

1. All tested foaming agents provided good mobility reduction in Ottawa sand in absence of oil and are thermally stable at steam flood conditions.
2. In the presence of residual oil the mobility reduction was delayed to varying extent depending on the nature of the surfactant.
3. Alkyl aryl sulfonate type surfactants (e.g. LTS 18, Chevron SD 1020, Suntech IV, and Stepanflo 80) provided relatively faster response compared to alpha olefin sulfonate dimer type surfactants (e.g. SD 1000).
4. Alkyl aryl sulfonates in general have higher adsorption on mineral surfaces than alpha olefin sulfonates.
5. Alkyl aryl sulfonates partition into the oil phase to a greater extent than alpha olefin sulfonate dimers.
6. Presence of insoluble solids in some surfactants can present well bore plugging problems. This was a problem with SD1020 (XP2416) and Stepanflo 1467 in our tests. A quality control test should be carried out prior to injection in the field for each batch of the chemical and filtration should be carried out when required.
7. Based on the lab results discussed in this report, Chevron SD 1000 was recommended as the most suitable product for field trial among the products tested.

1. INTRODUCTION

Steam injection is the dominant enhanced oil recovery process in the world accounting for more than 80 percent of tertiary oil production in recent years. In most cases the steam injection starts in the cyclic (huff-n-puff) mode and is eventually converted to the steam drive mode. Although the steam drive process has been generally successful in recovering oil, two types of problems can reduce its efficiency, namely gravity override and steam channeling.

In case of gravity override, gravitational forces cause the low density steam to rise to the top of the formation where it displaces oil. Once a thin zone at the top of the formation becomes depleted, a low resistance path is created for the steam to flow through. Therefore after the steam break through at the producing well a large portion of the injected steam continues to travel through the depleted zone at the top without displacing any oil. In case of channeling a relatively high permeability zone causes the steam to channel through that zone while bypassing a large fraction of the oil in adjacent lower-permeability zones.

Because of the high cost of the fuel to generate the steam, major research efforts by the oil industry have recently been directed towards overcoming the effects of gravity override and steam channeling. One of the more promising methods being developed is the injection of surfactants with the steam to form a resistive foam which can divert the steam into bypassed zones.

Several laboratory studies at steam flood conditions have been reported (1 -13). The available literature on steam foam technology suggested that it would not be difficult to find foaming agents which are stable at high

temperatures and provide stable foams at high temperatures. However, several questions remain unanswered concerning the oil-foam interactions and propagation of foam through porous media.

Several field trials of foams have also been reported (14 - 18) Of the five field tests conducted by CLD Group Inc. under a DOE cost shared contract, four were successful in improving sweep efficiency and in producing significant incremental oil. Shell has conducted two tests in Kern River field both of which demonstrated increased injection pressure, incremental oil production, improved sweep efficiency and the importance of non-condensable gas. In another Kern River test conducted by SUPRI, increased injection pressure and significant incremental production were reported. In summary, most of the field tests appear to be encouraging and show that foams can indeed improve the efficiency of steam drive operations.

Successful field trials of steam foam in Canada have not been reported. Since the field conditions for steam injection in Canada are significantly different from those in California, the results of the field tests mentioned above can not be applied to Canadian operations. Moreover, it is generally advisable to conduct laboratory tests with actual reservoir materials to answer the question of compatibility of the foaming surfactant with reservoir fluids.

The study described in this report was aimed at developing a foam treatment for one of the steam flood pilot currently operated by Texaco Canada Resources. It was conducted under a cost shared program funded jointly by Texaco Canada Resources and Canada Centre for Mineral and Energy Technology and . The main objective of the work was to identify a foaming agent which will be compatible with reservoir fluids and to provide an assessment of the

performance of selected chemical at its optimum concentration.

Currently there are about a dozen different steam foam diversion products being marketed by several different manufacturers. The chemical types represented by these products include alpha olefin sulfonate, alkyl aryl sulfonate, alkane sulfonate, dimerized alkyl sulfonate and some disulfonated products. In terms of thermal stability the alpha olefin sulfonate are less stable compared to dimerized alkyl sulfonate and alkyl aryl sulfonate. Based on the thermal stability considerations and reports of successful use in field tests, the following foaming agents were selected for screening with the reservoir fluid system:

I. STEPANFLO 80

Stepanflo 80 is a proprietary product of Stepan Chemical Company which is described as an alkyl aryl sulfonate by the manufacturer. It is one of the most heat stable foaming agents available and is stable up to 300°C. It is relatively quite viscous and may present some handling problems. In salinity and hardness tolerance it is claimed to be similar to Suntech IV by the manufacturer.

II. STEPANFLO 1467:

Stepanflo 1467 was supplied as an experimental product by Stepan Chemical Company. It is essentially the same chemical which was later commercialized as Stepanflo 80. The differences in the results obtained by this product and the commercial product were of the same magnitude as would be expected in two different batches of the same surfactant.

III. ENORDET LTS 18

Enordet LTS 18 is sodium salt of C-18 alkyl toluene sulfonic acid and is supplied as 15% active solution in water. It is less salt and hardness tolerant and may present some handling problems at low winter temperatures. It is considered to be thermally stable up to 300°C and is believed to be similar to Suntech IV in chemical structure. Several field tests have employed LTS 18 as the foaming agent with good results.

IV. CHASER SD-1000

Chevron's Chaser SD-1000 is sodium salt of a mixed dimerized sulfonate and is supplied as 40% active solution in water. It has very good salt and hardness tolerance and is easy to handle. Chaser SD-1000 is stable up to 250°C and shows only small degradation at 300°C. Chaser Sd-1000 has been used in several steam drive tests by Chevron with good results.

V. SUNTECH IV

This surfactant has been used in several laboratory studies and field trials. It is a synthetic alkyl aryl sulfonate possessing excellent thermal stability and very good foaming capability.

VI. CHEVRON XP 2416 (CHASER SD 1020)

This surfactant was supplied by Chevron Chemical Company as an experimental product. Later it has been commercialized under the name Chaser SD 1020. Chevron's literature claims it to be capable of foaming rapidly in the presence of a high residual oil saturation. It is also claimed to posses excellent thermal stability.

These surfactants represent a good cross section of what is available commercially and what appears to have good chances of success. The largest uncertainty lies in the effect of Frog Lake oil on the foam behaviour. It is expected that some foaming agents will perform better than others in presence of this oil.

1.1 Thermal Stability:

Thermal stability of these surfactants was not measured as part of this study. However sufficient information is available from the literature and previous work done at the Petroleum Recovery Institute. Suntech IV has been reported to be thermally stable up to 300°C (9). Stepanflo 1467, Stepanflo 80 and Enordet LTS 18 are synthetic Alkyl Aryl Sulfonates and should be comparable to Suntech IV in thermal stability. Chevron Chaser SD1000 is believed to be an alpha-olefin sulfonate dimer and is somewhat less thermally stable. However the manufacturer's literature shows that it lost less than 0.5% per day of surfactant activity due to thermal degradation at 260°C in a laboratory test. Therefore all three surfactants should be considered thermally stable for field application at Frog Lake.

1.2 Adsorption on Sand Surfaces:

Adsorption of the injected surfactant on sand surfaces is one of the important factors which control surfactant propagation through the formation. The level of surfactant loss due to adsorption depends on the surface area available for adsorption per unit volume of the formation, the mineral content of the formation, temperature and the nature of the surfactant. In general formations containing large amounts of clay mineral show higher adsorption

losses compared to clean sands. Figure 1 from Maini et.al.(19) shows that adsorption losses decrease with increasing temperatures and Suntech IV adsorbs more compared to the AOS surfactant. It has been suggested that the more hydrophilic surfactants will adsorb less (20). Since, both Stepanflo 80 and Enordet LTS 18 are chemically similar to Suntech IV, they will suffer similar levels of adsorption losses. Chevron Chaser SD-1000 contains dimerized alkyl sulfonates and is even more hydrophilic than the AOS surfactant tested by Maini et.al. It is therefore likely to adsorb even less than the AOS surfactant. Assuming the quality of Frog Lake sand is no worse than that of the Lindbergh sand used in the previous study, it is estimated that the adsorption losses for Chevron Chaser SD-1000 will be less than 0.3 mg/g of formation. This translates to approximately 0.5 kg of surfactant per cubic meter of the contacted formation.

1.3 Partitioning into Oil Phase:

The injected foam inevitably comes in contact with the steam flood residual oil. This stationery oil phase causes two problems. Most surfactants do not foam well in the presence of oil and the partitioning of the injected surfactant into the residual oil retards surfactant propagation through the formation. Generally the residual oil saturation has to be lower than a critical value which is surfactant dependent before the surfactant will produce an effective foam. Fortunately, the injection of a surfactant solution and non-condensable gas along with steam will mobilize a part of the residual oil even before the foam is effective in reducing steam mobility. Therefore continued surfactant injection will eventually reduce the residual oil saturation to a level at which the foam formation can start. The rate at

which the residual oil is mobilized and thus the time delay in foam formation depends on generation of low interfacial tensions. Surfactants which partition equally into the oil phase are likely to generate very low interfacial tensions but will not propagate as fast as the surfactant which does not partition into the oil phase. However the surfactant which partitions equally into the oil phase is likely to give faster foam response because it mobilizes the residual oil more effectively.

The partitioning characteristics of Chevron SD-1000 and Suntech-IV have been studied at the Alberta Research Council (21). Their data suggests that Chevron Chaser SD-1000 displays very little partitioning into oil while Suntech-IV partitions a lot. They also reported measurements of interfacial tensions and these confirm the observed partitioning behaviour. Therefore, of all surfactants selected for testing, only Chevron Chaser SD-1000 is of very low partitioning type. The others are likely to partition appreciably into the residual oil phase.

2. EXPERIMENTAL APPARATUS:

The experimental apparatus used for evaluations of the foaming agents is shown schematically in Figures 2a and 2b. The apparatus was designed for near adiabatic steam flow experiments. Heat loss from the core was minimized by maintaining the same temperature at the outside surface of the lead sleeve as exists inside the core. The temperature within the core was measured with thermocouples at 12 axial locations. Six band heaters placed on the outside surface of the sleeve were turned on and off by a microcomputer depending on the difference between the internal and external temperatures. This microcomputer was also used to record the values of the internal and external temperatures and other data recording functions.

The direction of flow in the sand pack was vertically downward. The fluid injection system was designed for injection of three separate fluid streams into the sand pack. One of these delivered super heated steam which was generated by injecting deionized water into a steam generator at constant flow rate. The second stream delivered hot water or a surfactant solution at constant rate while the third one provided nitrogen gas at constant rate which was controlled by a mass flow controller. The pressure drop across the sand pack was monitored with an electronic differential pressure transducer and a back pressure regulator maintained constant pressure at the core outlet. The following provides a brief description of the main components of the experimental system:

Pressure Vessel:

The pressure vessel was fabricated from 25 cm (10 inch) high carbon steel pipe and standard A.N.S.I. 900 lb flanges at one end and a hemispherical head at the other end. The vessel was hydraulically tested at 10 MPa. The

confining pressure used in most of the experiments was approximately 5 MPa.

Steam Generator:

The steam generator was fabricated by placing a 36 meter long, 6.3 mm diameter Inconel tubing inside an electrically heated, temperature controlled, insulated air bath. De-ionized water was injected into this tube by a positive displacement pump (Beckman model 100A). The air bath was operated at a temperature approximately 50°C higher than the desired steam temperature. The superheated steam produced by this device was conditioned by cooling in a second air bath which was kept at the desired steam temperature.

Data Acquisition System:

A HP 87 XM computer (manufactured by Hewlett Packard) coupled with a HP 3421 A data acquisition and control unit was used for recording experimental data on floppy disks. The data was also printed out in hard copy format as it was being recorded.

Back Pressure Regulator:

A gas loaded dome type back pressure regulator (manufactured in house) was used to maintain constant pressure at the outlet end.

Load Cell:

An Intertechnology cell (model T163a-50) and Aries AI11 signal conditione: was used to monitor amount of water injected into the steam generator.

Gas Mass Flow Controller:

A Brooks monitor/controller combination (models 5810B/5835D2) was used for constant rate gas injection.

Mixer:

A 6.3 mm diameter static in line mixer was used to mix the nitrogen gas

stream with the dry steam stream during foam injection phase of the experiments.

Core Heaters:

Six 200 watts band heaters (manufactured by Watlow) were placed outside the lead sleeve which was used to confine the core. Each of these was 7.6 cm wide and 10 cm in diameter.

Thermocouples:

Thermocouples used for monitoring the temperature profile within the core and at the out side surface of the sleeve were of multicouple variety. A twelve-point multicouple was used for monitoring the internal temperature. A pair of three-point multicouples was used for external temperatures. Several other single-point thermocouples were used for monitoring the temperature at different points in the flow lines. Figure 2 (c) shows the location of the thermocouples for monitoring the internal and external temperature profile of the core.

3. EXPERIMENTAL PROCEDURE

The preliminary experiments for screening commercially available foaming agents were conducted in cores prepared with Ottawa sand. Table 1. lists typical properties of these sand packs. A new core was prepared for evaluation of each foaming agent. The core was wet packed in a lead sleeve, to which the bottom end plate had been attached, using deionized water and 100 to 140 mesh Ottawa sand. After filling the sleeve with sand the top end plate was attached and the core was placed in a pre-conditioning vessel. This vessel was used for initial application of over burden pressure and leak testing the sleeve. If no leak was found the core was dried by flowing hot nitrogen through it. It was then evacuated and filled with produced Frog Lake brine. The volume of brine imbibed provided a direct measure of the pore volume. The core was then flooded with crude heavy oil while still confined under over burden pressure in the pre-conditioning vessel. The volume of water displaced by the oil was used to calculate the initial oil saturation.

After the oil flood the core was taken out of the pre-conditioning vessel and a 0.79 cm hole was drilled parallel to the length of the core through the bottom end plate to accommodate the thermocouple assembly. The core was then mounted in the pressure vessel shown in Figure 2(b) and the band heaters were placed around it. After closing the pressure vessel, nitrogen overburden pressure was applied.

Each core was steam flooded to reduce the oil saturation down to the steam flood residual, which was typically about 10 to 12 percent. These steam floods were carried out with 1.38 MPa back pressure at the core outlet. The core was then ready for foam testing. Foaming agents were tested initially by simultaneously injecting three fluid streams into the steam flooded core at

known flow rates; (1) the surfactant solution (at a known concentration), (2) the dry steam and (3) nitrogen gas. During foam injection the core was maintained at the steam temperature by the band heaters. The foam performance under these conditions was measured by comparing the pressure drop across the core with the base line value measured in absence of the surfactant. This increase in the pressure drop was used for comparing different surfactants. Other surfactant concentrations and flow rates were later evaluated to further define the foam performance in clean Ottawa sand cores.

Selected surfactants were later evaluated in reservoir cores. These cores were placed in the lead sleeve and a confining pressure of 5.0 MPa was applied. The core was then steam flooded down to a residual oil saturation which was typically about 18 percent. The foaming agents were tested by simultaneously injecting the surfactant solution, dry steam and nitrogen gas at different combinations of their flow rates and measuring the resulting pressure drop. In most cases the pressure drop was measured after the system appeared to reach an steady-state flow condition. However, occasionally when the approach to steady-state was very slow some measurements were taken without reaching the steady state.

4. RESULTS AND DISCUSSION:

4.1 Steam Flood Behaviour in Ottawa Sand Core:

As mentioned above a steam flood was carried out on each core used for evaluations of foams to obtain the desired steam flood residual oil saturation. Typical steam flood behaviour is shown in Figures 3 to 13. The steam was injected at nearly constant pressure and the differential pressure across the core was kept more or less constant by maintaining a constant back pressure at the production end of the core. Figure 3 shows the change in differential pressure during the steam flood. Except for a brief period at start during which very little steam goes into the core and towards the end when the steam generation capacity becomes the limiting factor, the pressure drop across the core varies within a narrow range. The average pressure drop for the case shown was 9.65 psi.

Figures 4 and 5 show the injection and production curves with time. The rate of steam injection increases gradually and becomes equal to the capacity of the pump. The fluid production vs. amount of steam injected is shown in Figure 6. A comparison of the total fluid production and the line with slope equal to one shows that during injection of first 300 g of steam the production is nearly equal to injection. This means that there was little or no vapour phase in the core up to this point. The difference between steam injection and total produced fluid grows beyond this point, showing development of a steam zone in the core. Figure 7 shows cumulative recovery vs steam injected for the run. The recovery behaviour appears to be a combination of hot water injection initially followed by a steam drive. Figures 8 to 10 show temperature vs time plots recorded by the 12

thermocouples placed along the length of the core. These also show that the top end of the core was below the steam temperature for almost three hours. The sharp rise in temperature at each thermocouple location corresponds to approach of the steam front. As would be expected in case of constant pressure injection the steam front did not move at constant speed. Figures 11 to 13 show comparison of internal and external temperatures at six different axial locations corresponding to midpoints of the six band heaters. Except for the time when the internal temperature is rising very rapidly due to approach of the steam front, the external temperature remains within few degrees of the internal temperature.

4.2 Foam Behaviour in Ottawa Sand:

Table 4 provides a comparison of the performance of various surfactants in Ottawa sand as well as in the reservoir core. The details of these results are discussed in the following:

4.2.1 STEPANFLO 80:

As mentioned earlier the pressure drop across the core at a given rate of foam flow was used as a measure of foam performance. The foam was generated by injecting a fluid mixture comprising 10 ml/min (water equivalent) of dry steam, 10 ml/min of 1 wt% surfactant solution and 50 SCCM (standard cubic centimeters per minute) of nitrogen gas. The base line pressure drop was established by injecting pure water in place of the surfactant solution and was about 5 psi. The pressure drop across the core increased gradually after switching from pure water injection to surfactant injection. It reached a plateau of 125 psi after 18 hours of continuous foam injection. The value of mobility reduction factor (the ratio of pressure drop with foam divided by the

base case pressure drop) at this point was about 25.

Since in the actual field case the flow rate decreases rapidly as the foam moves away from the injection well it is important to know the effect of flow rate on foam performance. Therefore, even at this preliminary screening stage some tests of flow rate sensitivity were carried out. This was done by reducing the flow rates of dry steam and surfactant solution by half in successive steps. As shown in Figure 14, the reduction in differential pressure was less than 50 percent in going from 20 ml/min (water equivalent) steam injection rate to 10 ml/min. The foam was actually more effective at 10 ml/min steam injection rate. However, a further 50 percent reduction in flow rate caused a severe decline in the differential pressure. This suggests that at this flow rate the foam was no longer effective in reducing steam mobility. A further 50 percent reduction later caused very little change in the differential pressure.

It is known that the foam flow in porous media involves a dynamic equilibrium between opposing forces, i.e. forces which cause collapse of the foam and forces which regenerate the foam (22). A critical minimum flow rate is required to regenerate the foam and overcome the forces causing foam collapse. The value of this critical flow velocity depends on the foaming agent being used, its concentration, the amount and type of oil present and the nature of the porous medium involved. It is apparent that for this system, the critical flow rate was between 5 ml/min and 10 ml/min.

The tests discussed above showed that a large volume of the foaming agent had to be injected before the foam started becoming effective in generating good mobility control. The reasons for this were not immediately clear. The amount of surfactant injected was much more than what would be required to

satisfy the adsorption and partitioning to residual oil phase requirements. The only other factor which appeared relevant was the effect of residual oil on foam formation and propagation. It was suggested in the literature that the oil concentration had to drop below a certain critical level before the foam could form and propagate. Therefore, the foam does not show a high pressure response until the excess oil is mobilized and driven away.

If the presence of residual oil is the reason for slow response then the foam would be expected to respond very quickly in an oil free situation. To test this hypothesis the experiments were repeated in an oil free core. As expected, in this case the buildup of pressure drop was very rapid. As shown in Figure 15 the pressure drop started rising almost immediately after the foam injection was started and reached a peak of 150 psi after four hours. The effect of flow rate was also evaluated in the oil free situation.

Figure 16 shows the pressure drop values at different steam injection rates. A comparison with Figure 14 suggests that the critical velocity for foam propagation is lower in the oil free core. Without the oil, even at 2.5 ml/min injection rate the foam was quite effective in reducing steam mobility. Figure 15 illustrates another interesting aspect of the foam behaviour. The increased differential pressure persisted long after the surfactant injection was discontinued. Apparently, the retention of the foaming agent within the porous medium is strong enough to supply the incoming steam with sufficient foaming agent for maintaining the foam for a considerable length of time.

4.2.2 STEPANFLO 1467:

As mentioned earlier, Stepanflo 1467 was an experimental version of the surfactant later commercialized as Stepanflo 80. Some of the earlier

experiments were carried out using this experimental product. Figure 17 shows the effect of flow rate on differential pressure in presence of residual oil saturation. A comparison of Figure 17 with Figure 14 shows that the two products behave similarly. The foam provided good mobility reduction at steam injection rates of 7 ml/min or higher but collapsed at 4 ml/min. Figure 18 shows the effect of increasing the nitrogen flow rate at fixed steam injection rate. As expected, higher nitrogen injection rates lead to higher pressure drops.

The changes in pressure drop with time during some of these measurements are shown in next three figures. Figure 19 shows the effect of changes in flow rate on foam behaviour. The base case pressure drop measured by injecting 10 ml/min (water equivalent) dry steam, 10 ml/min hot water and 50 SCCM (cc/min at standard conditions) nitrogen gas was approximately 5 psi. It should be mentioned that this core had been exposed to this surfactant previously and it is likely that some of the residual oil had been mobilized. Therefore, the quick response toward very high pressures shown in this figure does not imply that this surfactant would respond as quickly in a freshly steam flooded core. The first half of this figure shows that the foam almost totally collapses as a result of reducing the steam injection rate from 10 ml/min (5 ml/min dry steam + 5 ml/min surfactant solution) to 5 ml/min. Increasing the flow rate back to 10 ml/min regenerates the foam.

It was not obvious whether such collapse would also occur if the flow rate was reduced gradually as would be the case in the field. Therefore, in the next series of experiments the steam injection rate was reduced in much smaller steps. This type of experimentation was continued next day after regenerating the foam at 10 ml/min total injection rate. As shown in the

Figure 20, reducing flow rate in smaller steps results in less dramatic changes in pressure drop, however, the pressure drop does reach very low levels at low flow rates. Therefore, it appears that the foam formed with this surfactant would become less effective in providing mobility control at low flow rates. Similar results were obtained in repeat testing on subsequent days as shown in Figures 21 (a) and 21 (b). These tests also showed that the reproducibility of pressure drop at high steam injection rates was quite good.

4.2.3 ENORDET LTS18:

The performance of this surfactant in an Ottawa sand core containing steam flood residual oil is shown in Figure 22. The most striking observations in this test were the quick response in differential pressure and the high peak pressure. The injection pressure increased by more than 200 psi in less than three hours of foam injection. As shown in Figure 23, the effect of flow rate on differential pressure was similar to the previous surfactants. The critical injection rate needed to sustain the foam was between 5 ml.min to 2.5 mil/min. Based on these results Enordet LTS18 appeared to be very promising.

4.2.4 SUNTECH IV:

Suntech IV performance in the bench mark test was similar to Enordet LTS 18 in quickness of the pressure response but some what less spectacular in the value of the peak pressure. Figure 24 shows the effect of varying the injection rate of surfactant solution at fixed dry steam and gas injection rates on differential pressure across the core. Fairly high differential pressure was maintained at the lowest surfactant injection rate (1.25 ml/min

surfactant solution with 10 ml/min dry steam leading to 88 percent steam quality). Figure 25 shows the changes in pressure drop with time during some of the tests with this surfactant. An interesting observation noted during these tests concerned the residual effect after surfactant injection was stopped. With continued steam injection at rate of 10 ml/min and no surfactant injection, the pressure drop remained an order of magnitude higher than the base case. When the steam injection was stopped for a short time and then restarted at 2.5 ml/min the pressure drop showed gradual increase. After several hours of flow the steam injection rate was again increased to 10 ml/min. The pressure drop across the core once again reached approximately the same level which existed just after stopping the surfactant injection. It appears that the surfactant retained in the core is sufficient to sustain the foam long after the surfactant injection is terminated. It should be kept in mind that dry steam was being injected in this experiment. It is likely that the surfactant will be removed more effectively if low quality steam was injected.

4.2.5 SODIUM DODECYL BENZENE SULFONATE:

This surfactant failed to produce high differential pressures in the bench-mark test. The pressure drop across the core increased to approximately four times the base case value and remained stable for nearly 24 hours of continued foam injection. To confirm that this lackluster result was not due to some abnormality in the core, the core was washed with hot water injection and a second test with a different surfactant (Chevron Chaser SD1000) was carried out. This led to a peak pressure drop of approximately 200 psi. The core was again washed with water and injection of sodium dodecyl benzene

sulfonate was resumed. The pressure drop again stabilized at approximately 20 psi confirming the poor foam performance obtained with this surfactant. Figure 26 shows the results of this second test.

4.2.6 CHEVRON CHASER SD1000:

Figure 27 shows the performance of this surfactant in the bench-mark test. The buildup of pressure drop after initiating foam injection in the steam flooded core was relatively slow. It took more than ten hours to reach the plateau in pressure drop values. Since this was one of the more popular commercially available surfactant for steam flood applications, and this slow response was a reason for some concern, we repeated this test in another freshly steam flooded core. As shown in Figure 28, this time it took about 8.5 hours to reach the pressure drop plateau. The two runs are compared in Figure 29. The main difference in the two runs is in the time elapsed before the pressure starts increasing at a fast rate. After this onset of pressure buildup, the two runs were almost indistinguishable. The time required for onset of the pressure buildup is likely to be related to the time involved in the reduction in oil saturation to a level compatible with the foam starting from the original steam flood residual oil saturation. The steam flood residual oil saturation was somewhat higher in the first test.

The effect of flow rate on differential pressure is shown in Figure 30. This surfactant was able to maintain a foam at the lowest steam injection rate (2.5 ml/min) in presence of the residual oil saturation.

This surfactant was tested at a lower concentration (0.25 wt percent) also. As shown in Figure 31 fairly high differential pressure was obtained even at 50 percent lower concentration.

Figure 32 shows the changes in pressure drop when the injection rate of surfactant solution was decreased while keeping the dry steam injection rate constant. Note that the reduction in injection rate of the surfactant solution lowers the overall surfactant concentration but increases steam quality. Foam type pressure drops were maintained down to 0.1 percent overall surfactant concentration. A comparison with a similar test performed with Suntech IV (see figure 24) shows that in case of Chevron Chaser SD1000 the pressure drop declines rapidly after the surfactant injection is terminated. One possible reason for this behaviour is that the surfactant retention (in the sand) is much smaller in case of this product.

Effect of nitrogen flow rate on differential pressure is shown in Figure 33. Increasing nitrogen injection rate had little or no effect on differential pressure across the core suggesting that only a small amount of non-condensable gas will be needed for adequate foam performance with this surfactant.

4.3 Foam Behaviour in Reservoir Cores:

Based on overall performance, there were two promising candidates for further evaluations in field cores; Enordet LTS 18 and Chevron Chaser SD 1000. LTS 18 was excluded due to its high adsorption on reservoir rock and partitioning into the oil. Moreover, this product is no longer being marketed. Towards the later stages of this investigation Chevron Chemicals introduced a new experimental product (XP 2416) which was claimed by Chevron to be superior to LTS 18 or any other similar product in the market.

Therefore we chose to include this product in our investigation as discussed in the following.

4.3.1 Chevron Chaser SD 1000:

The foam behaviour of this surfactant in Frog Lake reservoir core was similar to that observed in Ottawa sand. The buildup of pressure drop across the core after initiating foam injection into a steam flooded core was gradual and needed about 10 hours to stabilize. This initial foam injection was carried out at 20 ml/min steam injection rate (at 50 % quality). After reaching what appeared to be a stable pressure drop plateau, the effect of injection rate was evaluated. As shown in figure 34, the pressure drop decreased with the overall flow rate but remained substantially above the base case at 5 ml/min steam injection rate. The main purpose of this test was to determine whether the surfactant was compatible with the reservoir minerals and could be propagated in the reservoir. The results were considered positive.

4.3.2 Chevron Chaser XP 2416.

This experimental surfactant was strongly recommended by Chevron. Their tests had shown it to posses good thermal stability and oil tolerance. Its foam properties in clean sand packs were known to be good. Therefore, we did not test it in Ottawa sand before carrying out the reservoir core tests. In the reservoir core it developed very high pressure drops soon after the foam injection was initiated. Figure 35 shows the effect of surfactant concentration on pressure drop. Surprisingly this surfactant was able to produce high pressure drop even at 0.063 weight percent concentration. As

discovered later this high pressure drop was not entirely due to good performance of the foam but also due to presence of insoluble solids in the surfactant solution.

The pressure drop at different flow rates is shown in Figure 36. The pressure drop at the lowest flow rate was unusually high and appeared to be increasing with time. The results appeared to be too good and made us skeptical about their validity. The behaviour suggested that some other form of plugging might be occurring. This suspicion was reinforced by persistent problems in the check valves of the HPLC type pumps which were being used to pump the surfactant solution. Therefore we decided to filter the solution through two different types of filters in separate tests. Figure 37 shows the pressure drop behaviour of the filtered solutions. The solution filtered through 0.22 micron filter developed much smaller pressure drop compared to that filtered through 1.5 micron size filter. This suggests that the surfactant solution contained filterable material which was apparently causing significant plugging within the core. In view of the possibility of near well bore formation damage, this surfactant could be unsuitable for use in the field.

4.4 Measurements of the Effects of Process Parameters:

The detailed measurements of the effects of various process parameters were carried out with Chevron SD-1000 surfactant. This surfactant was selected for field application on basis of its cost, its published adsorption characteristics and satisfactory performance in the previously described

tests. The cost per active kg of bulk surfactant was similar for all of these products in California, however the delivered cost in Calgary was lowest for Chevron SD 1000 due to its high active content.

4.4.1 Effect of Surfactant Concentration:

Effect of Chaser SD-1000 concentration on differential pressure is shown in Figure 38. Three different surfactant concentrations were tested in a Frog Lake core at steam flood residual oil saturation. The figure compares the pressure drop across the core obtained with foam to the base case pressure drop. Excellent mobility reduction was obtained at 0.25 percent and 0.5 percent concentrations. At 0.125 weight percent concentration the pressure drop was less impressive but still several times higher than the base case.

4.4.2 Effect of Flow Rate:

Effect of flow rate was evaluated by measuring the differential pressure across the core at three different steam injection rates. These tests were carried out at 0.25 weight percent surfactant concentration, 50 percent steam quality and a fixed nitrogen injection rate of 50 SCCM. As shown in Figure 34 the values of pressure drops were 162 psi, 141 psi and 78 psi at 20 ml/min, 10 ml/min and 5 ml/min respectively. The foam appeared to collapse at lower flow rates.

4.4.3 Effect of Steam Quality:

The effect of steam quality was examined by measuring the differential pressure at 0.25 percent concentration and in absence of the non-condensable gas. As shown in Figure 39, the pressure drop becomes comparable to the base

case when steam quality becomes zero. This would be expected since the foam can not exist without a gas phase being present. In presence of the non-condensable gas the effect of declining steam quality was less dramatic. In fact at a high ratio of non-condensable gas the pressure drop was almost insensitive to steam quality.

4.4.4 Effect of Non-condensable gas:

Figure 40 presents the pressure drop values measured at different injection rates of the non-condensable gas (nitrogen). These tests were carried out at 0.25 percent overall surfactant concentration and 50 percent steam quality. The injection rate of non-condensable gas had very little effect on pressure drop. It should be mentioned that the tests were carried out in the order shown. Therefore, even though no non-condensable gas was being injected in the third segment, some trapped gas may have been present in the system. In actual reservoir case some non-condensable gas will always be present due to the presence of dissolved gas in oil and liberation of carbon dioxide from the rock at steam temperatures.

5. PROPOSAL FOR A FIELD TRIAL

5.1 INTRODUCTION

Steam-foam is applied in the field in three general methods as listed below:

(1) Continuous Method: This calls for a continuous injection of surfactant and non-condensable gas which will give a better propagation of foam in the reservoir. Generally, 0.5% by weight of active surfactant concentration in the liquid phase is injected with steam. This method is the most effective but also the most costly.

(2) Slug Method: This is a near wellbore treatment. Generally few hundred kg of surfactant is injected at a higher concentration than continuous method. This method is the least costly but its effectiveness is limited to the near wellbore region.

(3) Semi-continuous Method: This method seems to be the most popular method. It is halfway between continuous and slug treatment with the hope that it will produce results which are closer to continuous injection with a significant cost reduction. This technology was developed and applied by Chevron Oilfield Research in various fields in California (see Table 2 for more information).

Based on these considerations we would recommend this last method of injection with some modification. In order to create a good initial response

the surfactant should be initially injected at about 0.75% (or higher) active concentration for a few days and once a significant pressure response is observed then it should be reduced to 0.5% concentration based on the liquid phase of steam (50 % quality) or over all 0.25%.

5.2 FIELD APPLICATION

Based on the lab results, Chevron SD1000 steam drive additive is recommended as the foaming agent for field application (Chevron Chaser 1020 is also appears to be promising but due to the possible plugging and formation damage it is not recommended at this time). In this proposal steam rate is assumed to be 600 BPD.

Also, based on the recent experience of the steam-foam projects carried out in California and various discussions in foam sessions of 1989 SPE Regional Meeting in California, in order to obtain a reasonable foam propagation in the reservoir, the length of the foam test is recommended to be about 12 months.

The field injection plan is summarized as follows:

(1) Co-inject natural gas continuously at a rate of 30-40 MCFD (20-27 scf/min) during the entire project life.

(2) Co-inject Chevron Chaser SD1000 at a rate of 44 lbs/hr or 20 kg/hr (28 lbs/hr active) for 8 hr/day for 14 days (525 ml/min).

(3) Follow with co-injection of Chevron Chaser SD1000 at a rate of 29 lbs/hr or 13 kg/hr (19 lbs/hr active) for 8 hr/day.

NOTE; (a) During the steam-foam test, a minimum of 0.5% active material

(based on liquid volume of steam) should be injected (in our plan steam quality is assumed to be 75% with a rate of injection of about 600 BPD).

(b) Injection pressure should be kept below formation fracture pressure at all times.

(c) The above injection plan could be altered during the steam-foam process depending on pressure and production response if it is required; e.g.

  (i) If initial pressure response is slow, the concentration of the surfactant could be increased for a short period of time to obtain faster response.

  (ii) If the pressure response to the steam-foam test is quick, then Part 3 could be started earlier.

(d) Production from the thermal project, as well as from the wells on primary production adjacent to the thermal project, should be monitored frequently to assess the incremental oil due to the steam-foam test.

(e) Frequently monitor surfactant concentration in fluids produced from the thermal project, as well as from the well on primary production adjacent to the thermal project is required. This is to assess the surfactant propagation during steam-foam test.

5.3 COST ESTIMATE & SURFACE INJECTION FACILITY

This project requires 38,000 lbs of active chemical (Chevron Chaser SD1000) at an approximate cost of CDN$60,000 (including transportation cost). Also, it will require 15,000 MCF of natural gas at a cost of CDN$23,000 and an

additional cost for the rental of a gas compressor with a 30-40 MCFD capacity and a chemical pump. The detail of surface facility required for the project is shown schematically in Figure 41.

To date various field results obtained in California by using Chevron Chaser SD1000 are reported to produce 50-250% improved recovery or rate of recovery. Some of these are listed in Table 2. Also the product handling information is given in Table 3. The total chemical volume required to achieve these field results was in the range of 0.5-5 lbs per incremental barrel of oil recovered. This incremental recovery may, however, be partly produced by wells outside of the pilot pattern which can be assessed based on the history of production in and around the thermal pilot to date.

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TABLE 1.
Typical petrographic properties of the Ottawa sand cores used for screening the foaming surfactants

Core Length	45.0 cm
Diameter	9.2 cm
Pore Volume	1,100 ml
Porosity	0.37
Absolute Permeability	3.5 darcy
Initial Oil Sturation	0.85
Steam Flood Residual Oil Saturation	0.15

TABLE 2

PERFORMANCE SUMMARY OF THREE CHEVRON CHASER SD1000

STEAM ADDITIVE FIELD TESTS IN CALIFORNIA

Test Name	Date	Problem	Pay m	Gravity °API	Injection	Concentration Wt. %	Response Months	Oil Rate Increase %	Incremental Oil* m^3/Kg Active Chemical	Time Perio Months
Kern Front Section 27 Pattern 8-1N	1985-11	Steam Channelling	1.5-9.0	13	2 days/wk for 5 mo.	.5	1	31	.21	4
McKittrick Section 16Z Patterns 10-2W and 10-3AW	1985-11	Steam Override	17.7	12	2 days/wk for 6.5 mo.	.78	3.5	333	.30	6
Midway Sunset Section 15A Pattern 8-10W	1985-04	Steam Override	122	14	Continuous 4 months	.5	< 1	40	.31	6

* Incremental Oil during the time period shown. All three tests are incomplete.

TABLE 3

PRODUCT HANDLING INFORMATION

Chevron Chaser SD1000

- mildly alkaline solution
- clear amber liquid
- pour point: -2°C
- viscosity: at 21°C - 64 cp
  at 0°C - 85 cp
- density 8.9 lbs/gal.
- specific gravity 1.07
- 40% active

TABLE 4

Comparison of the performance of various surfactants in the presence of residual oil saturation for steam in Ottawa sand

Surfactant type:	Differential Pressure (psi) at different flow rates (ml/min)			
	20	10	5	2.5
Stepanflo 80	125	75	8	8
Stepanflo 80*	155***	90***	60***	35***
Stepanflo 1467	108	92	67	8
Enordet LTS 18	280	200	165	6
Suntech IV	125	100	-	-
Chevron SD 1000	205	107	75	60
Chevron SD 1000**	162	140	77	-
Chevron XP 2416**	265***	255***	210***	230***

* No residual oil present (Clean sand)

** Reservoir core used in place of the Ottawa sand

*** The results were influenced by plugging at the injection face of the sand pack due to presence of solid particles associated with the surfactant solution.

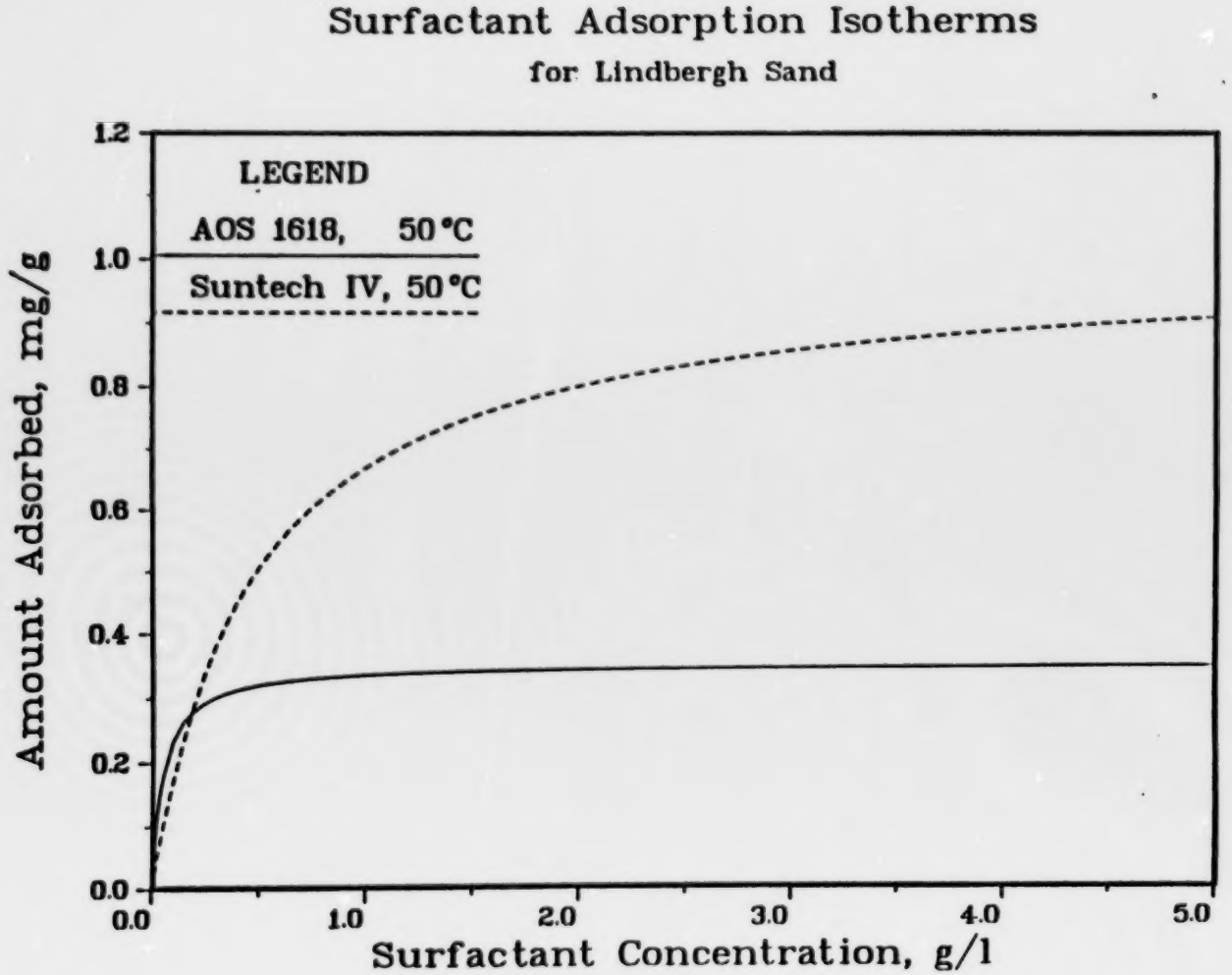

Figure 1. Comparison of adsorption isotherms of alkyl toluene sulfonate (----) and alpha olefin sulfonate (——) on Lindbergh sand

FOAM FLOODING

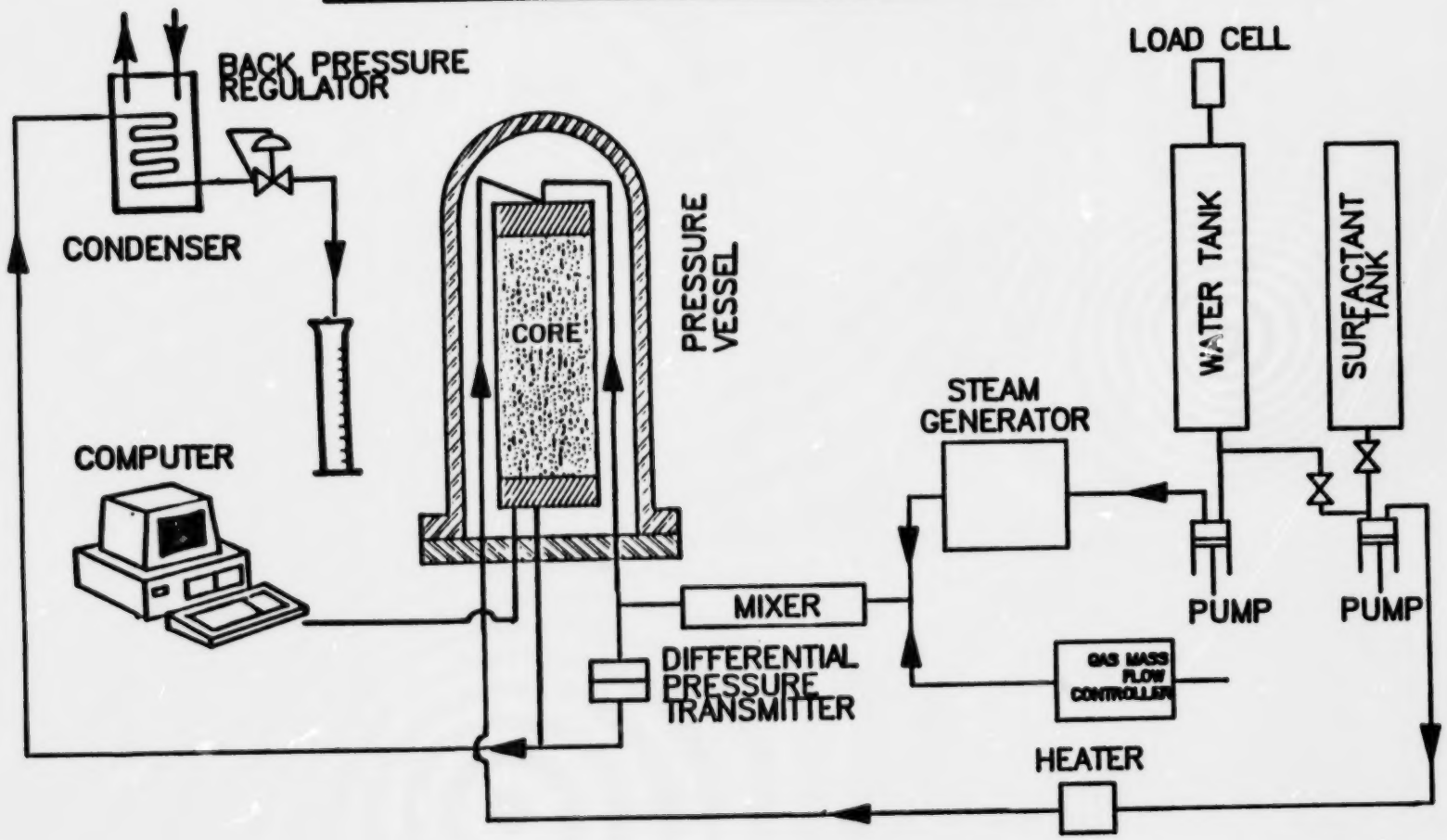

Figure 2(a): Schematic diagram of the experimental apparatus

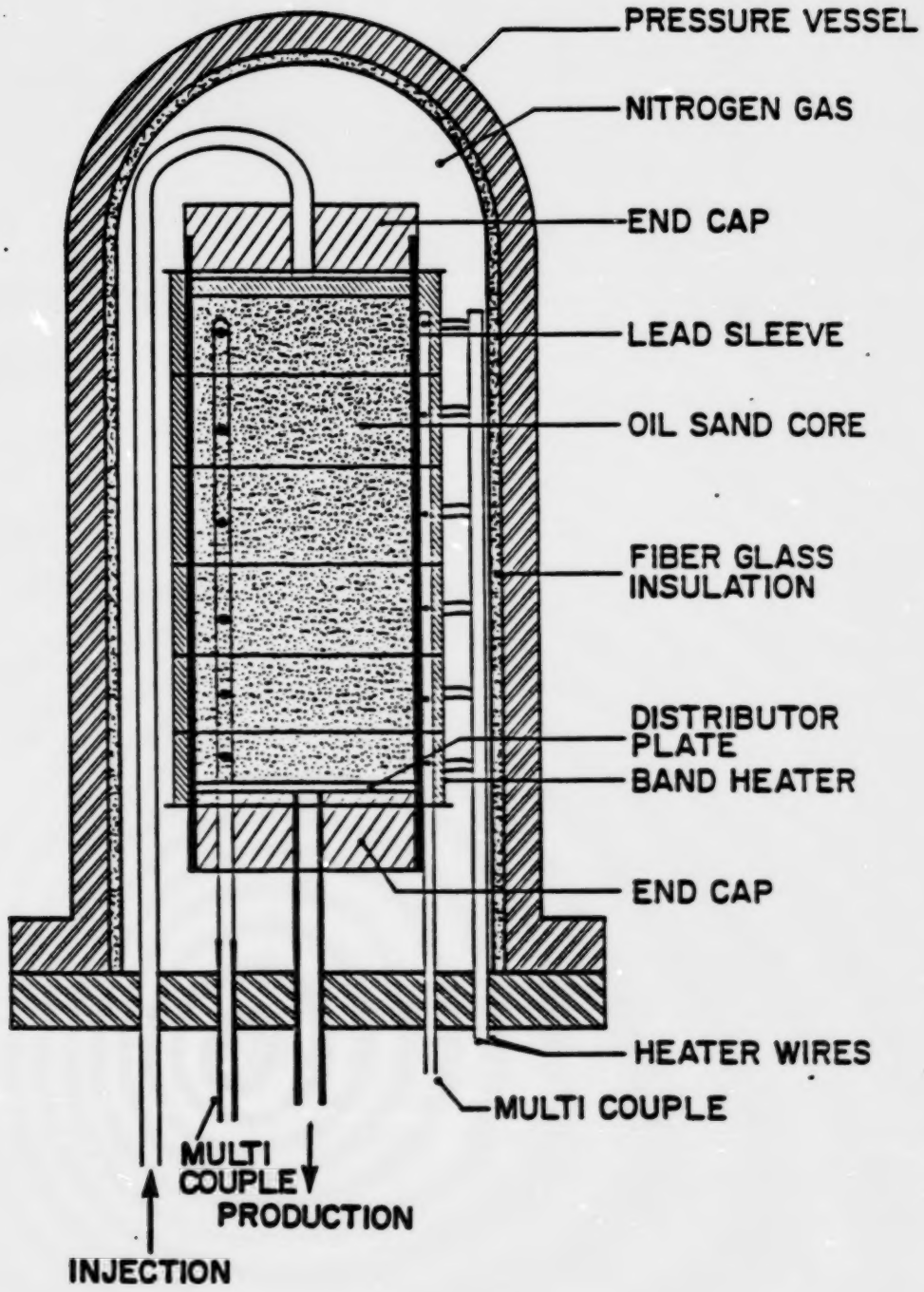

Figure 2(b): Schematic diagram of the core holder

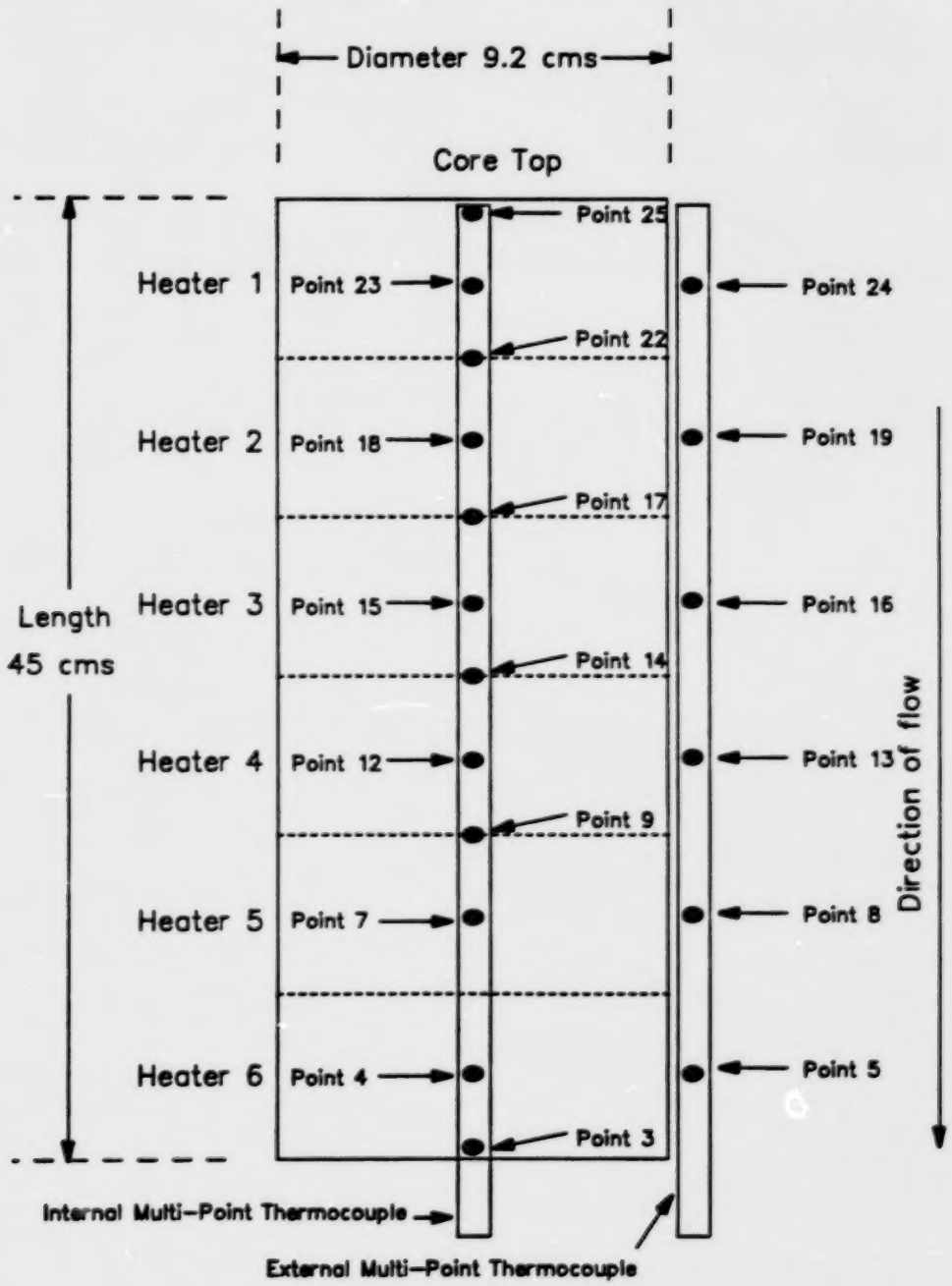

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Figure 2(c): Location of the internal and external thermocouples

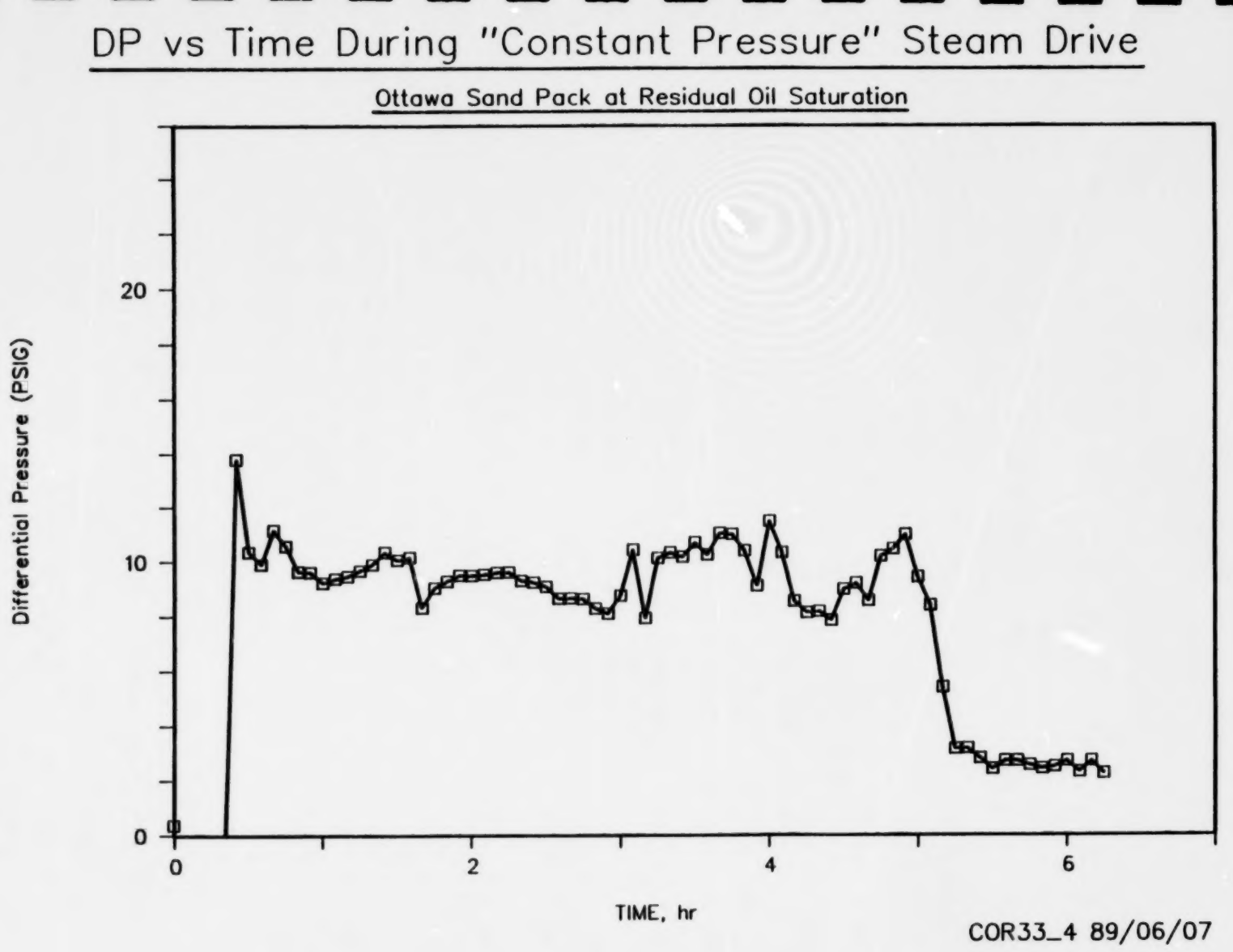


Figure 3: Steam injection pressure during the "constant pressure" steam flood

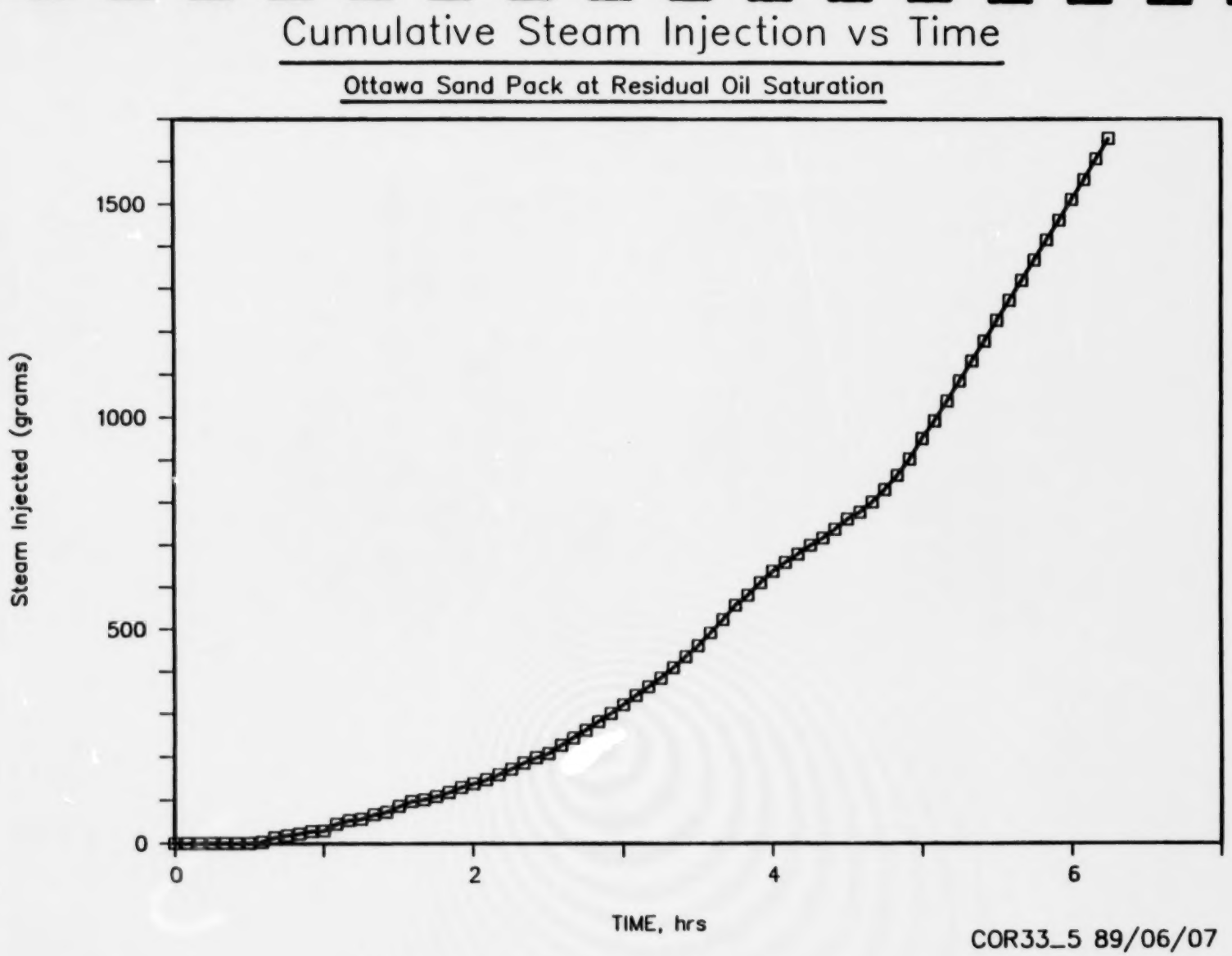


Figure 4: Cumulative steam injection vs time

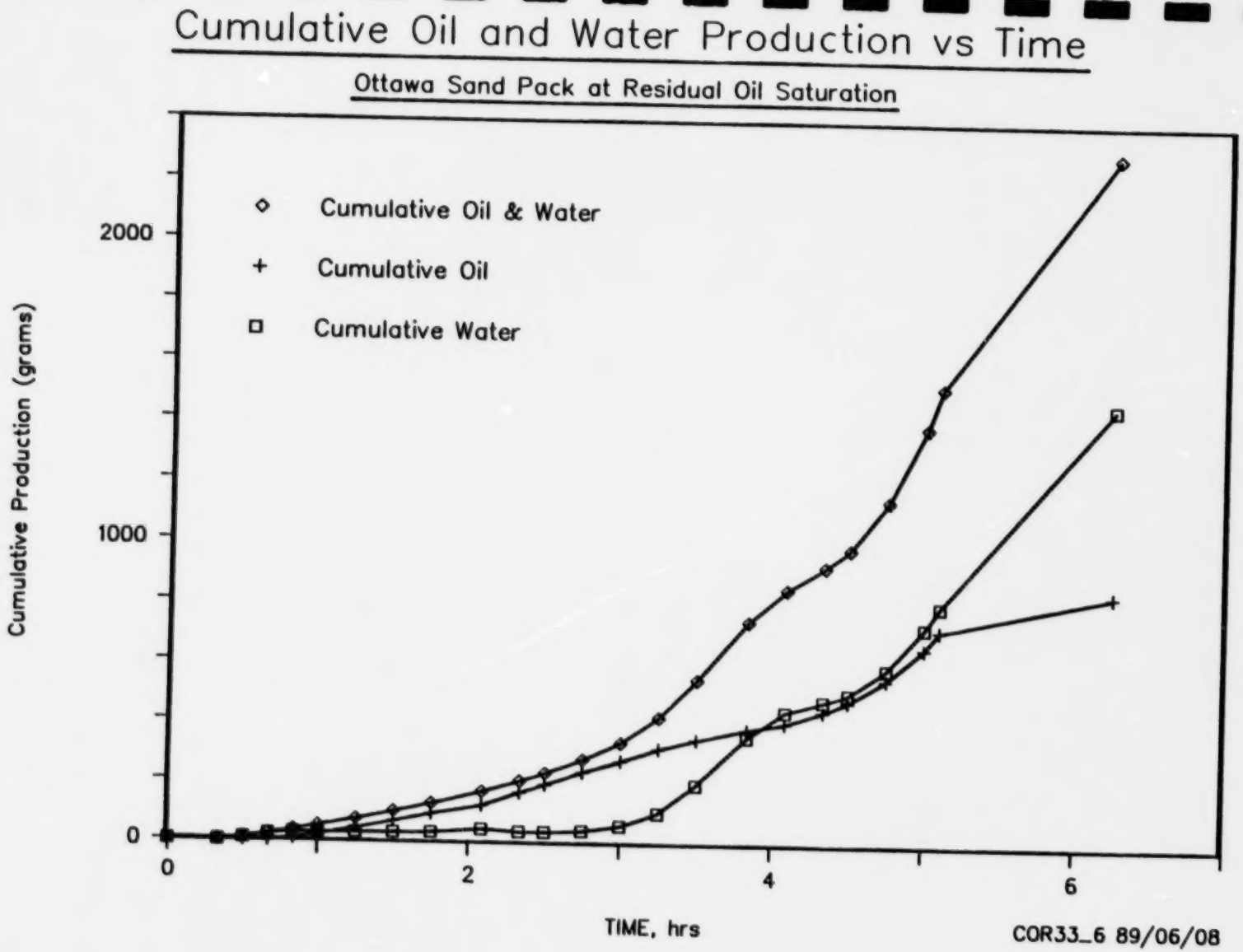

Cumulative Oil and Water Production vs Time
Ottawa Sand Pack at Residual Oil Saturation
Cumulative Oil & Water
Cumulative Oil
Cumulative Water
Cumulative Production (grams)
2000
1000
0
0
2
4
6
TIME, hrs
COR33_6 89/06/08

Figure 5

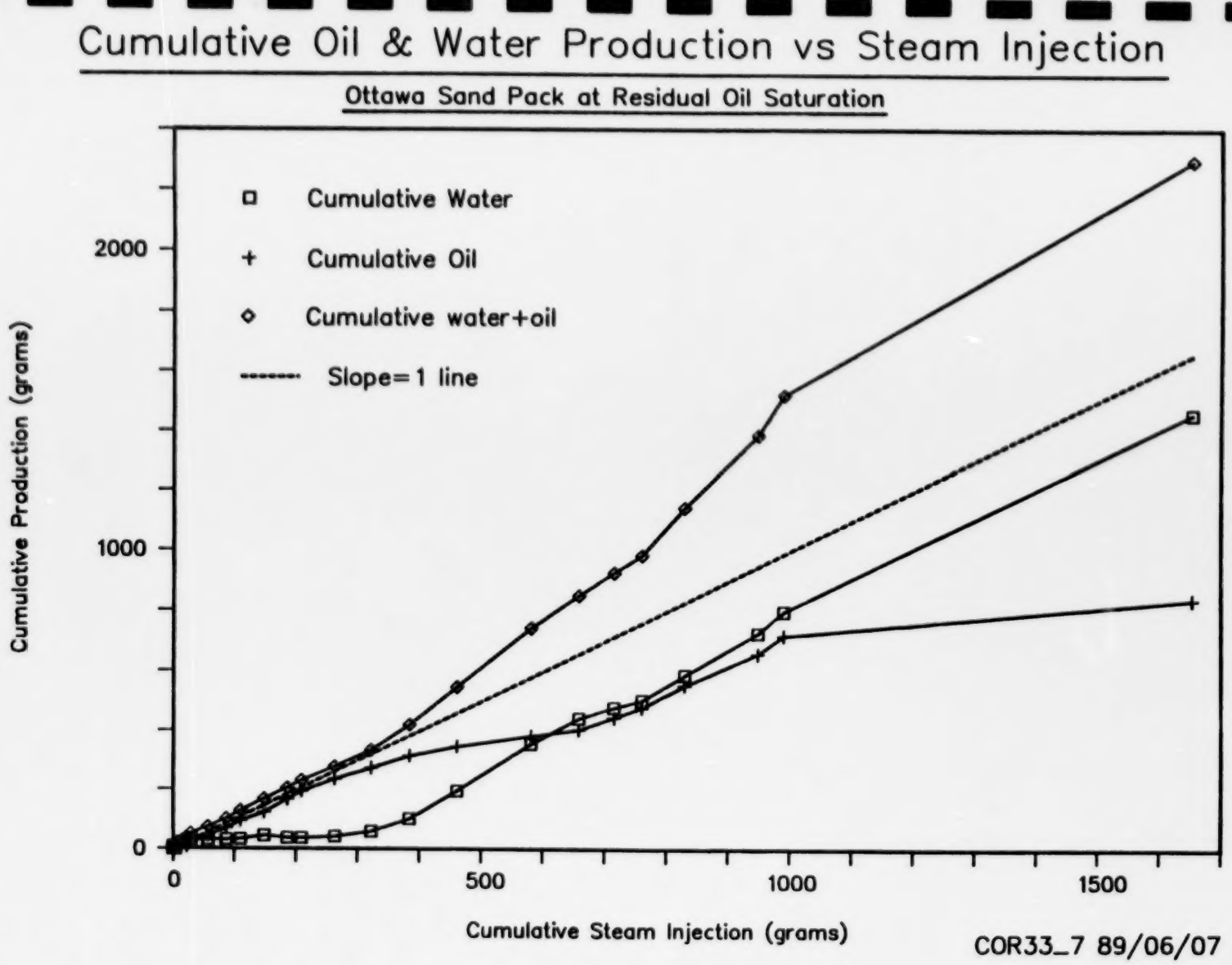

Cumulative Oil & Water Production vs Steam Injection
Ottawa Sand Pack at Residual Oil Saturation
Cumulative Water
Cumulative Oil
Cumulative water+oil
Slope=1 line
Cumulative Production (grams)
2000
1000
0
0
500
1000
1500
Cumulative Steam Injection (grams)
COR33_7 89/06/07

Figure 6

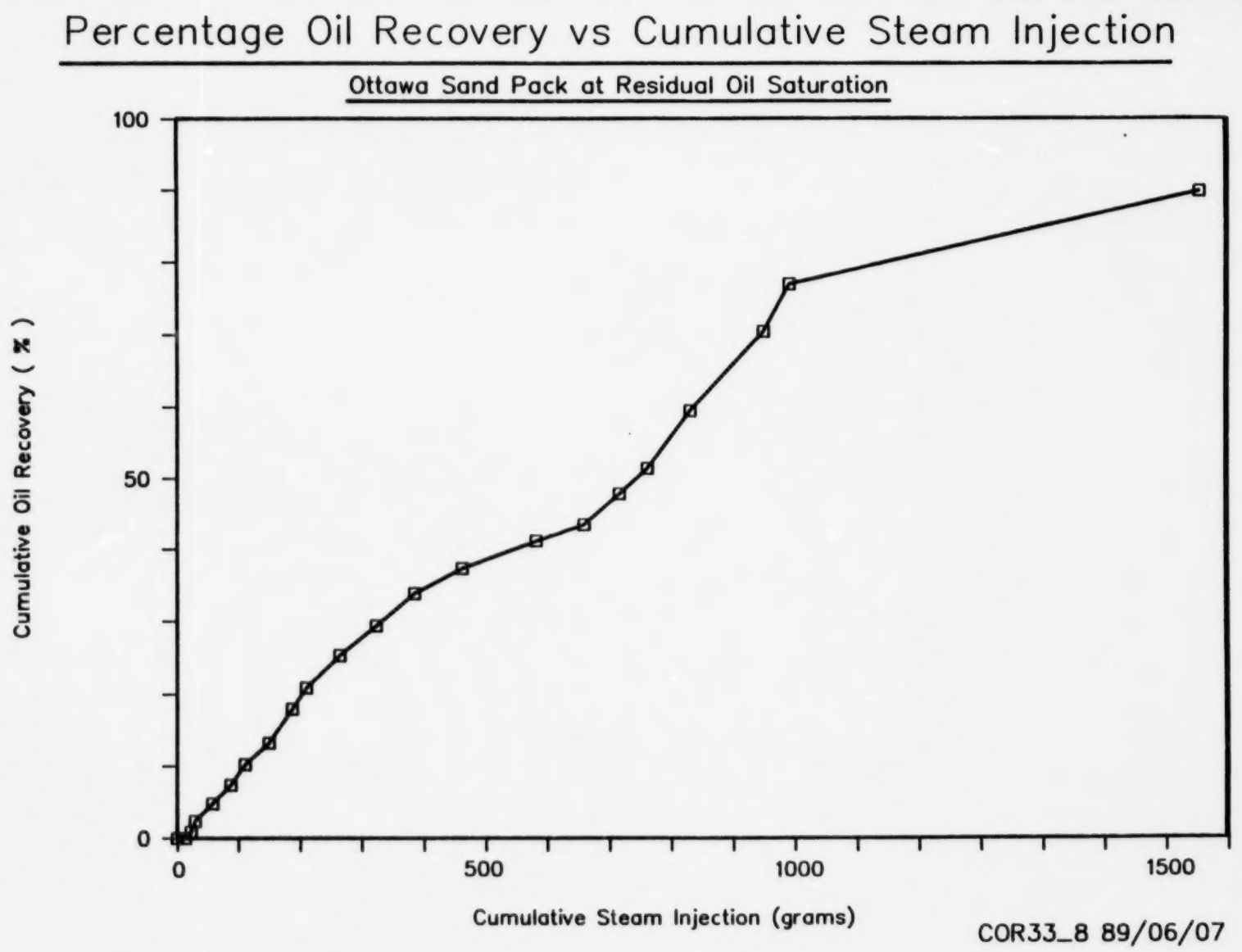

Percentage Oil Recovery vs Cumulative Steam Injection
Ottawa Sand Pack at Residual Oil Saturation
100
50
0
Cumulative Oil Recovery (%)
0
500
1000
1500
Cumulative Steam Injection (grams)
COR33_8 89/06/07

Figure 7

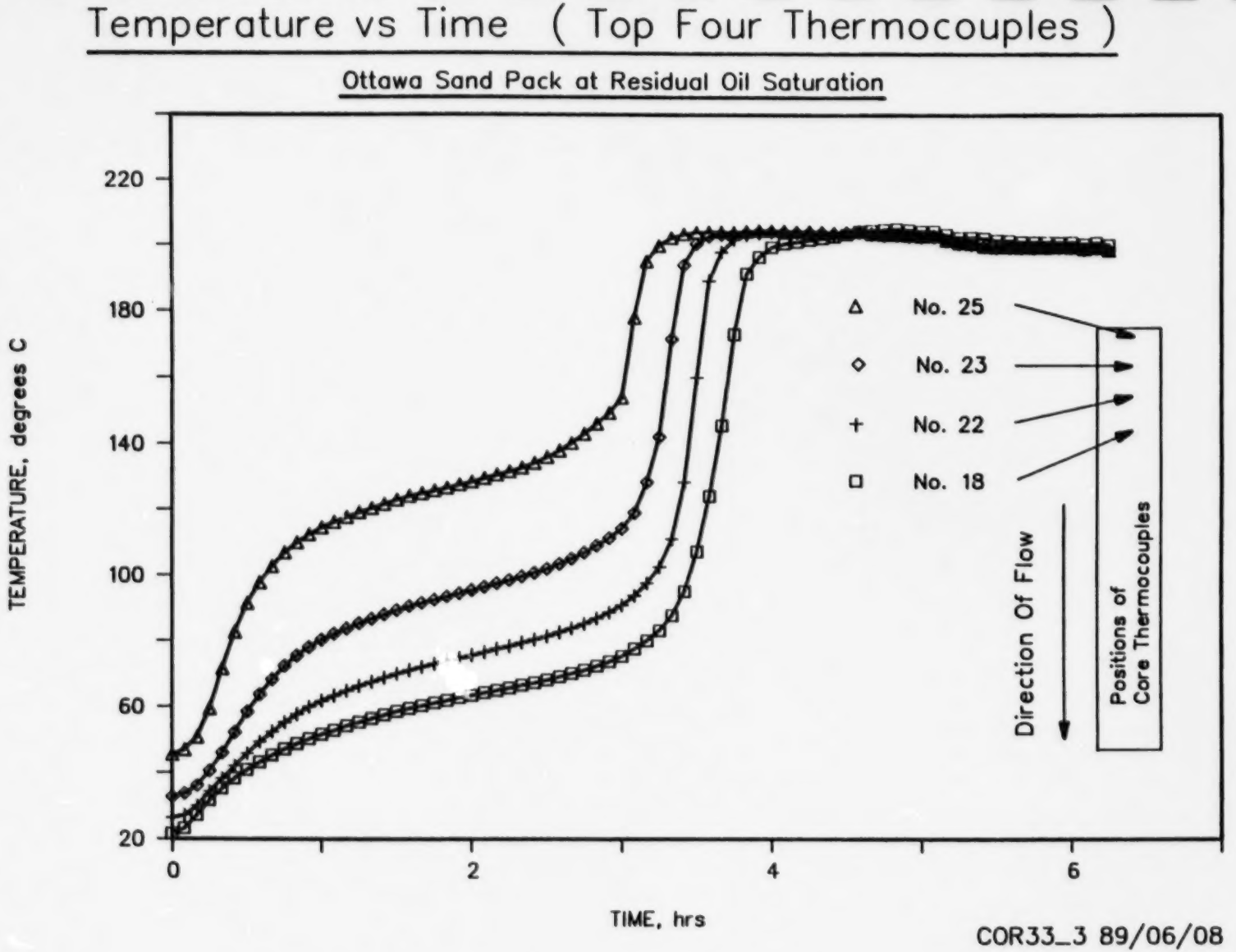

Temperature vs Time (Top Four Thermocouples)
Ottawa Sand Pack at Residual Oil Saturation
TEMPERATURE, degrees C
220
180
140
100
60
20
0
2
4
6
TIME, hrs
No. 25
No. 23
No. 22
No. 18
Direction Of Flow
Positions of Core Thermocouples
COR33_3 89/06/08

Figure 8

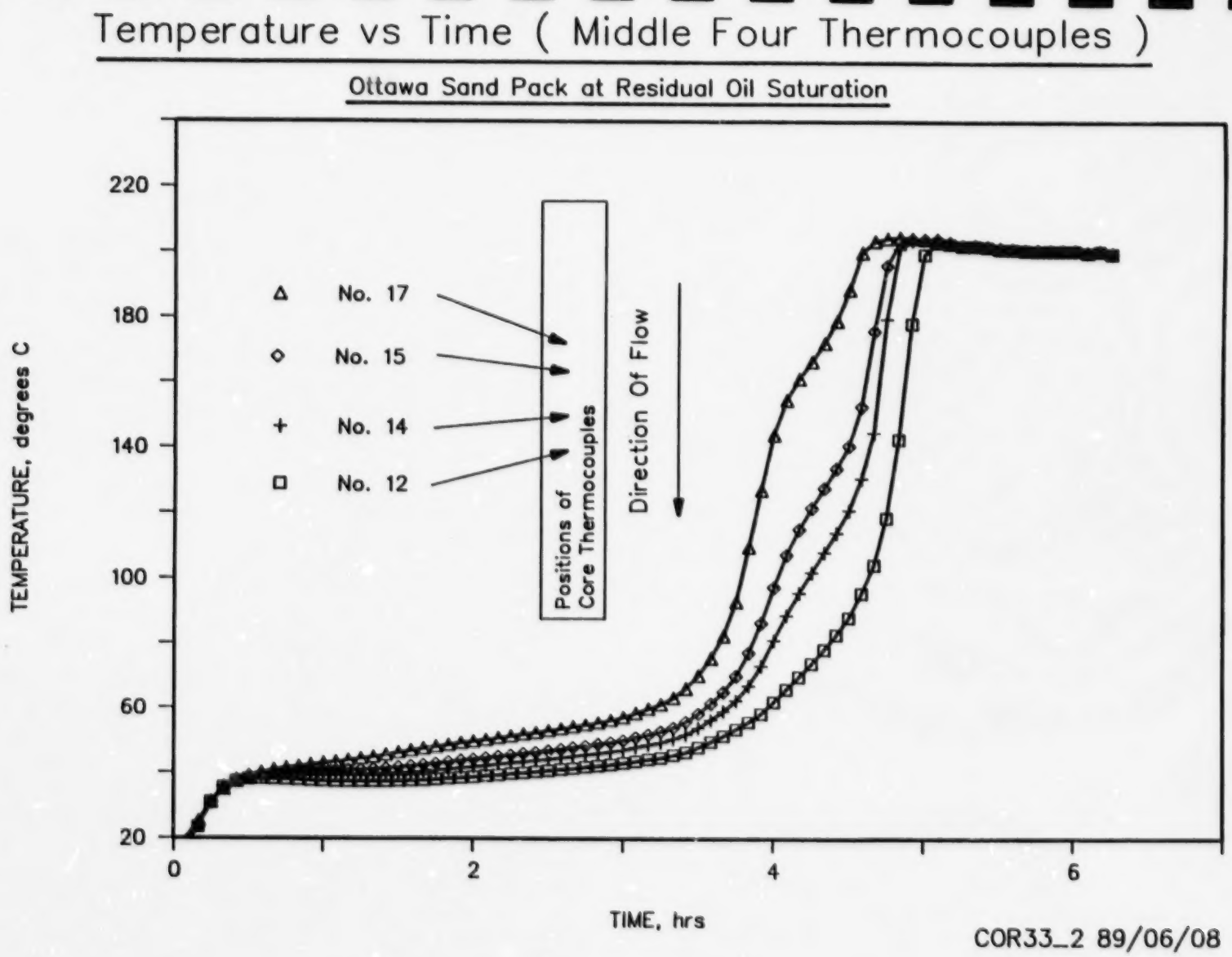

Temperature vs Time (Middle Four Thermocouples)
Ottawa Sand Pack at Residual Oil Saturation
TEMPERATURE, degrees C
220
180
140
100
60
20
0
2
4
6
TIME, hrs
No. 17
No. 15
No. 14
No. 12
Positions of Core Thermocouples
Direction Of Flow
COR33_2 89/06/08

Figure 9

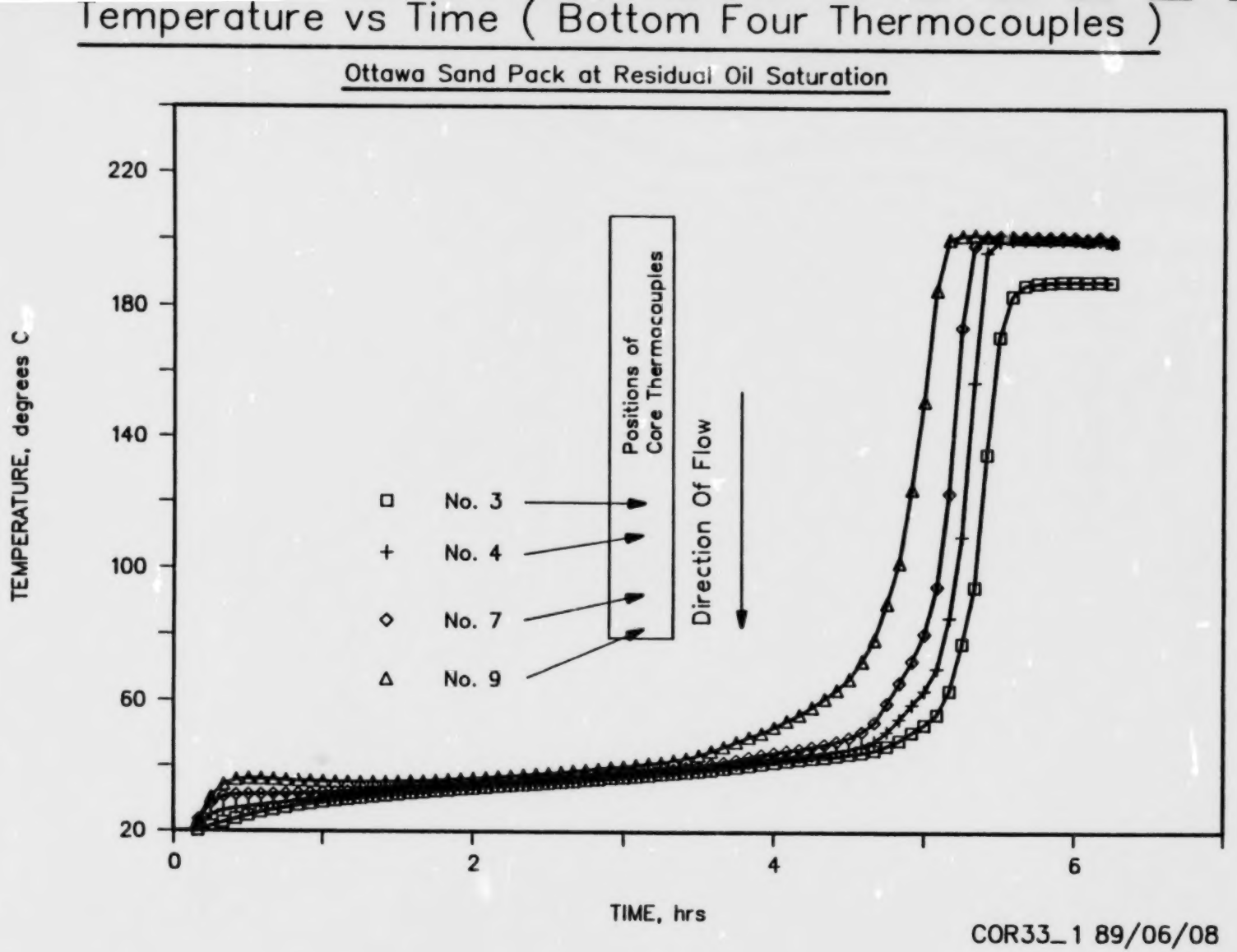

Temperature vs Time (Bottom Four Thermocouples)
Ottawa Sand Pack at Residual Oil Saturation
TEMPERATURE, degrees C
220
180
140
100
60
20
0
2
4
6
TIME, hrs
No. 3
No. 4
No. 7
No. 9
Positions of Core Thermocouples
Direction Of Flow
COR33_1 89/06/08

Figure 10

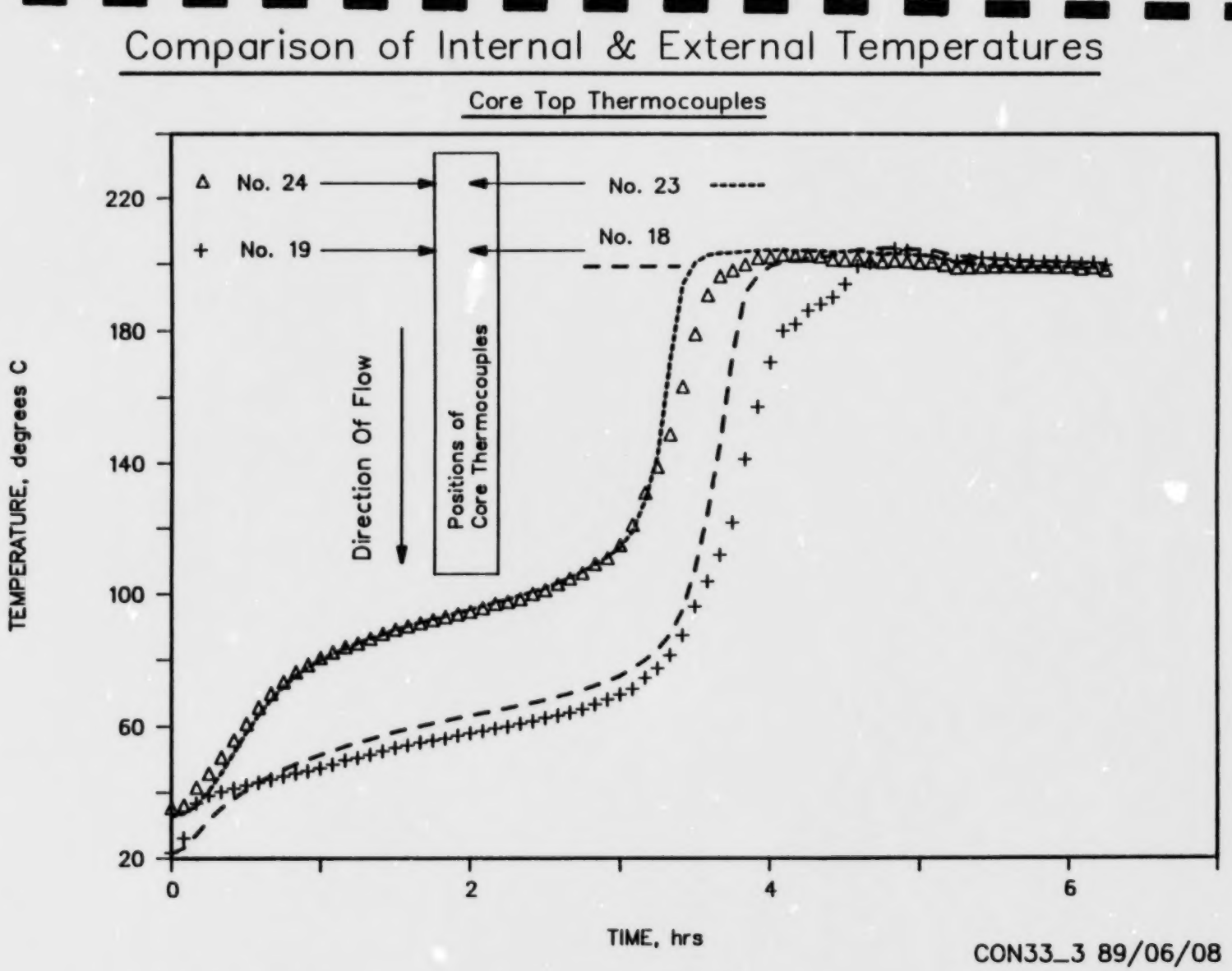

Comparison of Internal & External Temperatures
Core Top Thermocouples
Δ No. 24
+ No. 19
No. 23
No. 18
Direction Of Flow
Positions of Core Thermocouples
TEMPERATURE, degrees C
220
180
140
100
60
20
0
2
4
6
TIME, hrs
CON33_3 89/06/08

Figure 11

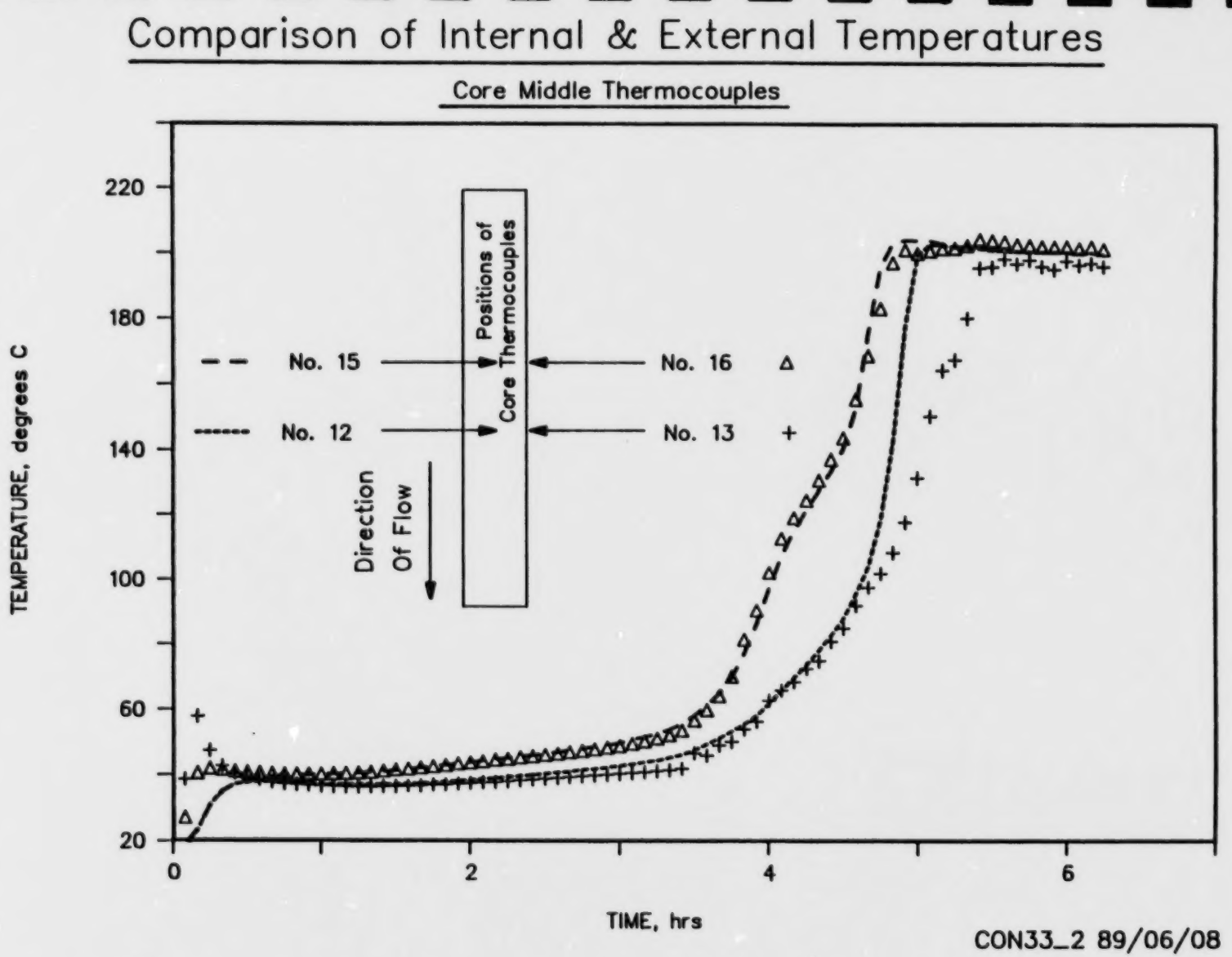

Comparison of Internal & External Temperatures
Core Middle Thermocouples
TEMPERATURE, degrees C
220
180
140
100
60
20
0
2
4
6
TIME, hrs
Positions of Core Thermocouples
No. 15
No. 16
No. 12
No. 13
Direction Of Flow
CON33_2 89/06/08

Figure 12

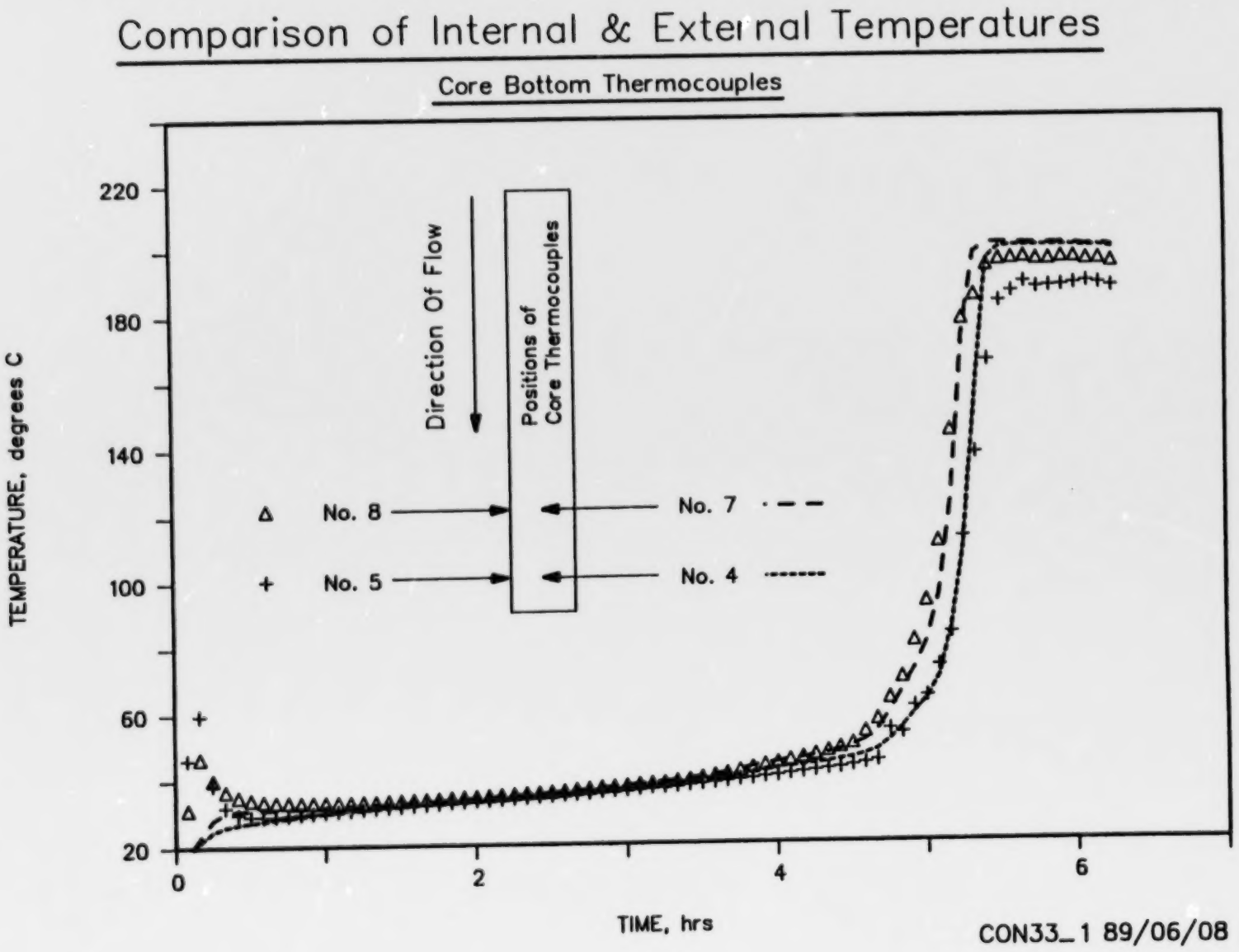
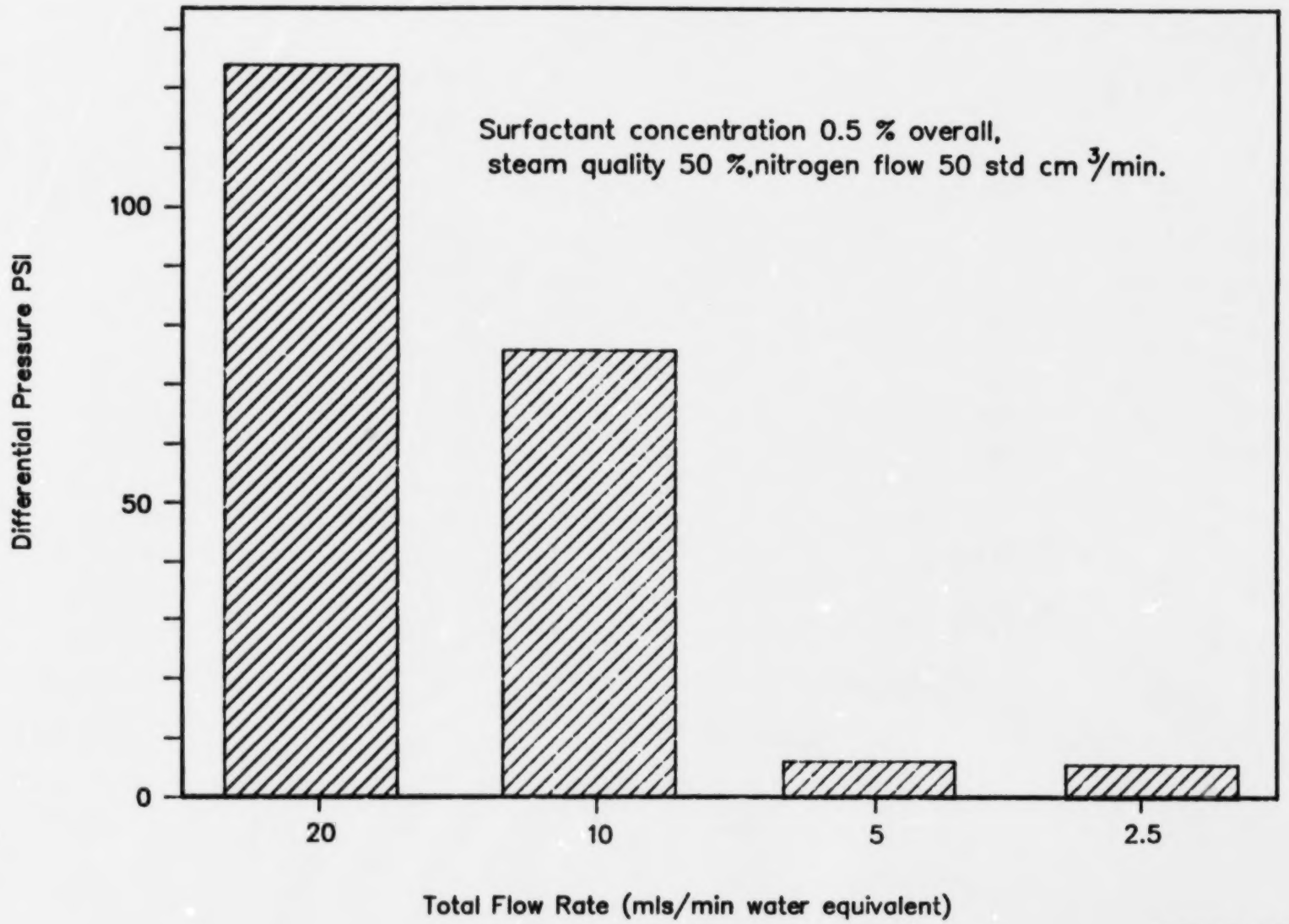

Comparison of Internal & External Temperatures
Core Bottom Thermocouples
TEMPERATURE, degrees C
220
180
140
100
60
20
0
2
4
6
TIME, hrs
Direction Of Flow
Positions of Core Thermocouples
No. 8
No. 5
No. 7
No. 4
CON33_1 89/06/08

Figure 13

Effect of Flow Rate on DP for Stepanflo 80

Ottawa sand pack at residual oil saturation



FL8087 89/05/04

Figure 14

Effect of Flow Rate on DP for Stepanflo 80

Clean Ottawa sand pack;overall surfactant concentration 0.5%

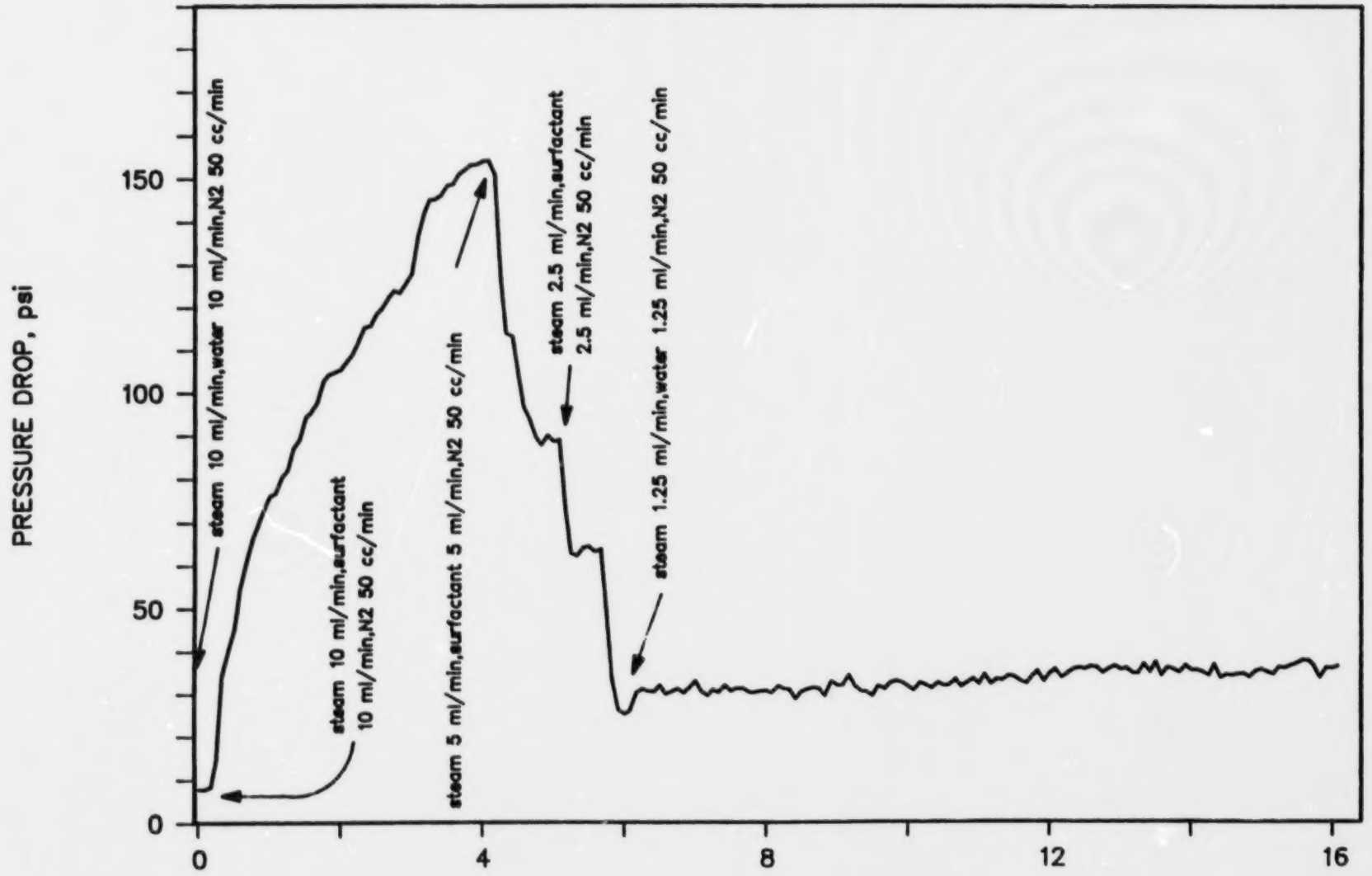


Figure 15

TVP 1310 89/05/05

Effect of Flow Rate on DP for Stepanflo 80

Clean Ottawa Sand Pack

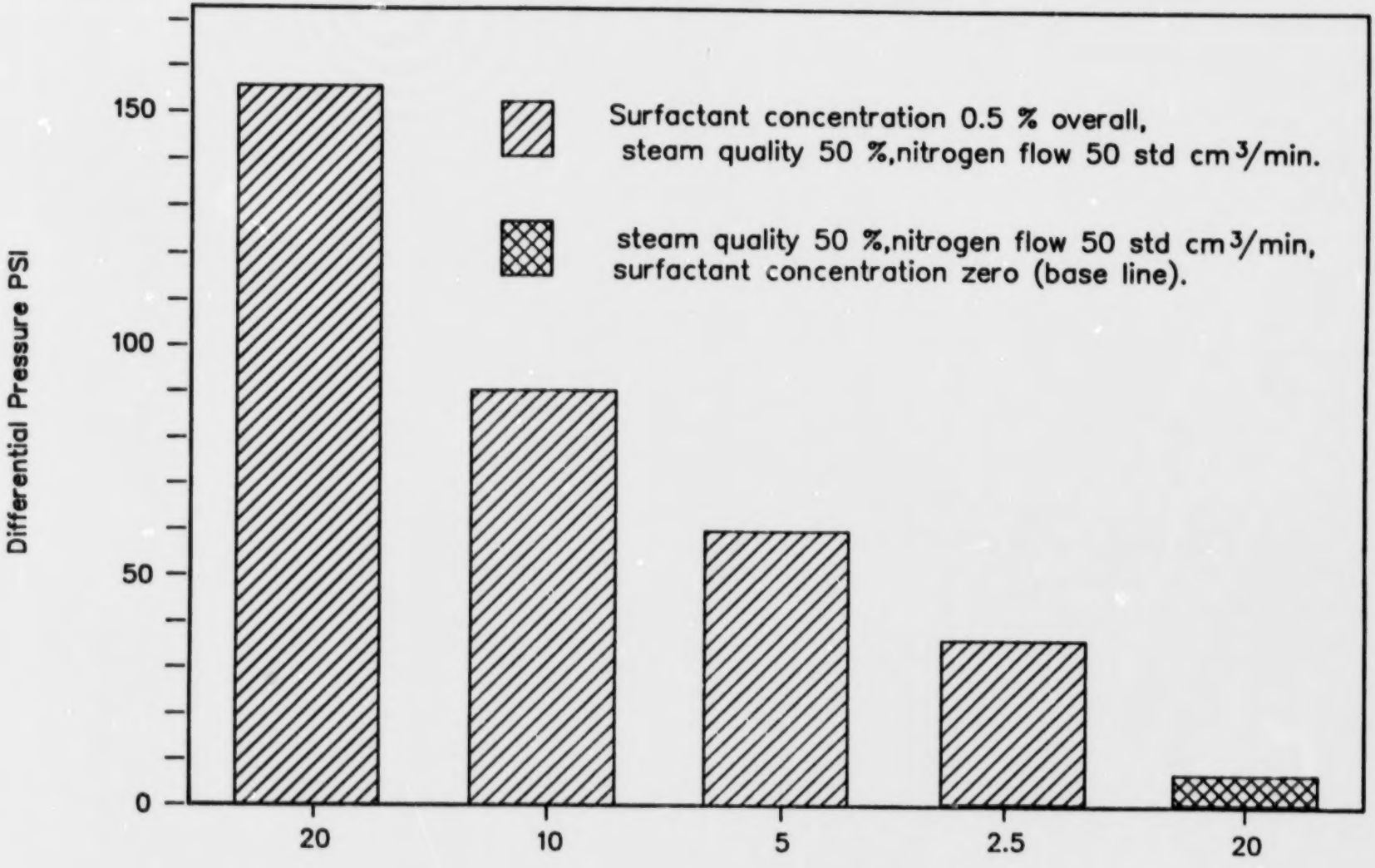


Figure 16

FL80CS 89/05/05

Effect of Flow Rate on DP for Stepanflo 1467

Ottawa sand pack at residual oil saturation

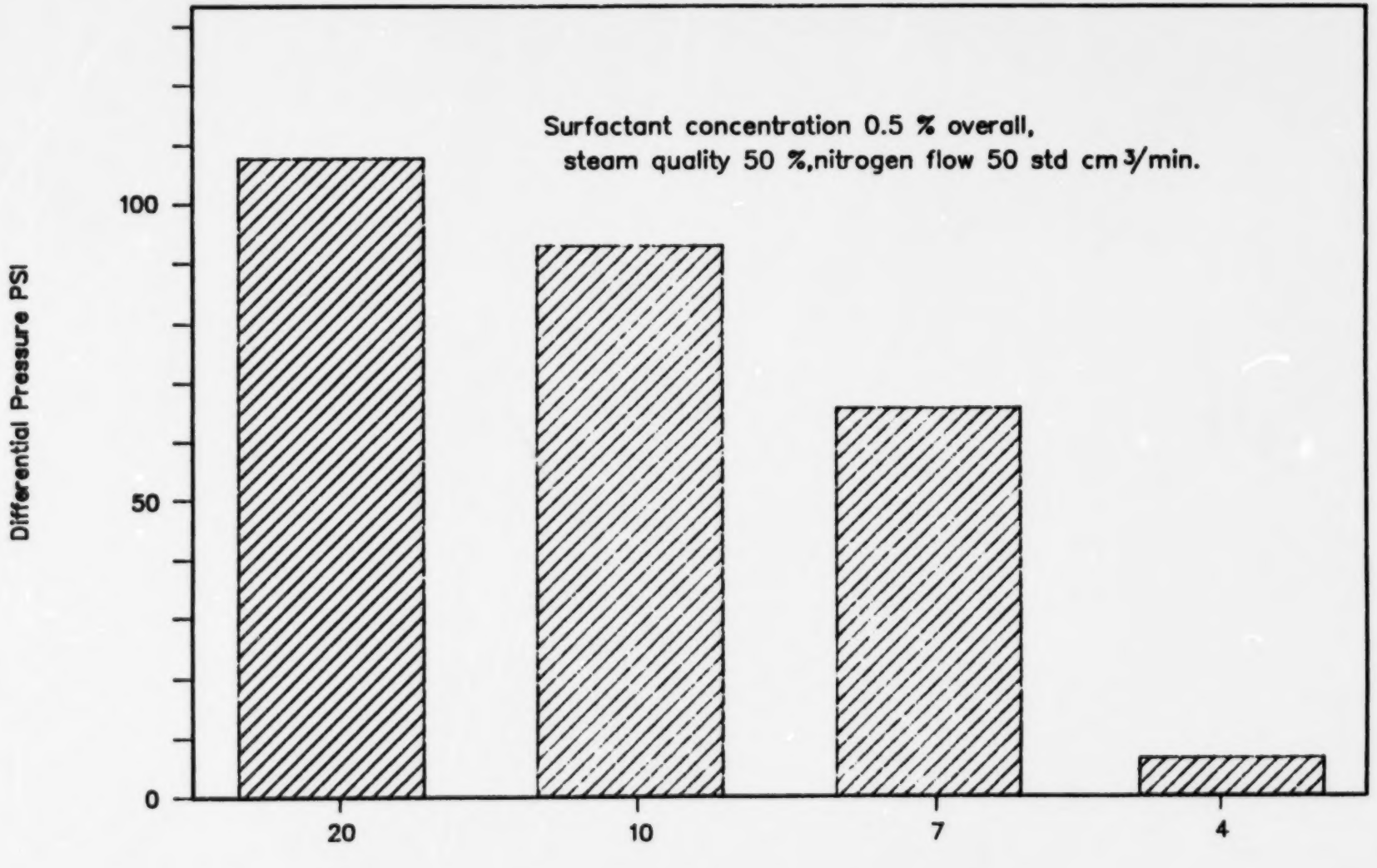


Figure 17

FL 1467 89/05/03

Effect of N2 Flow Rate on DP for Stepanflo 1467

Ottawa Sand Pack at Residual Oil Saturation

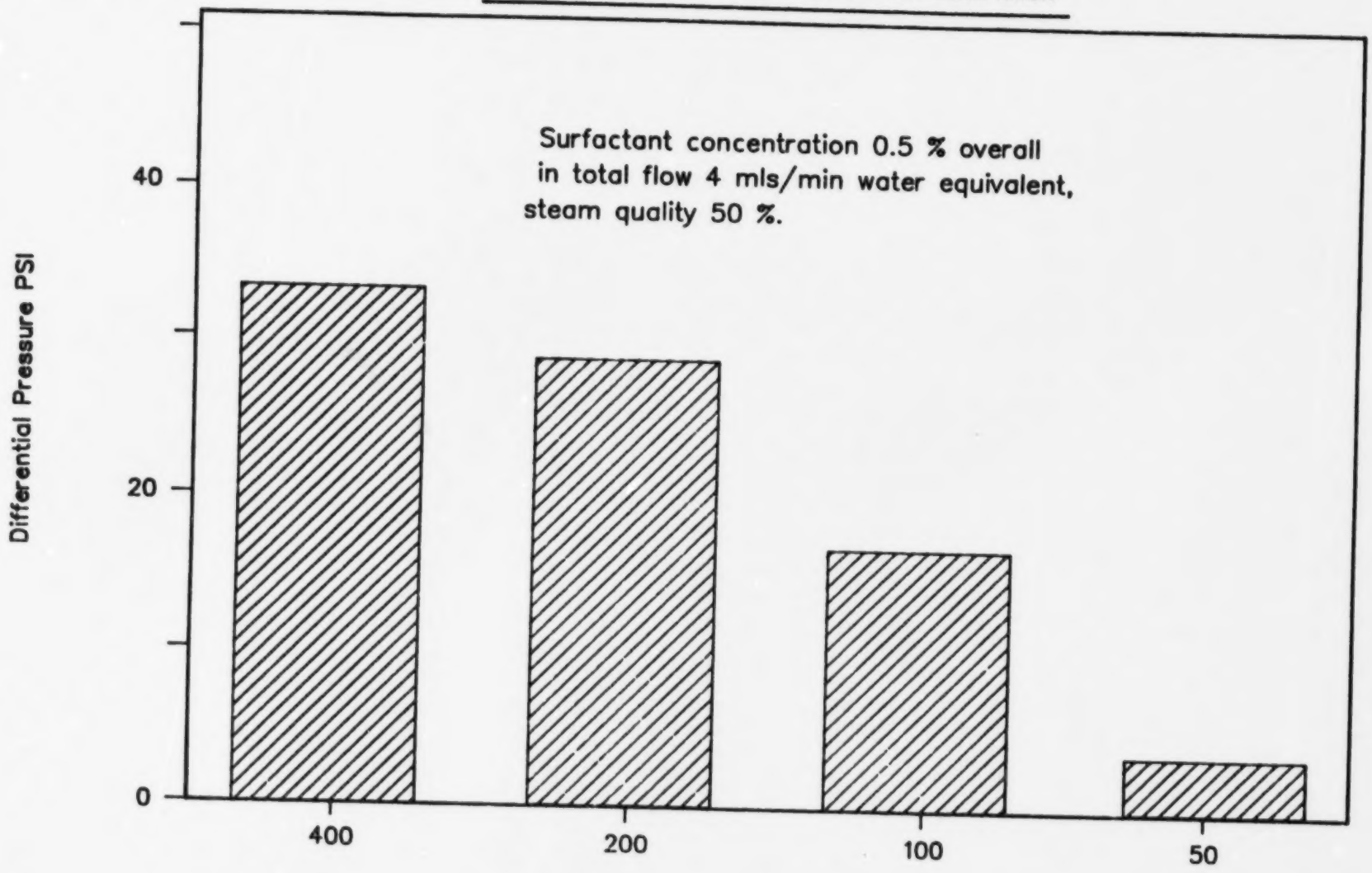


Figure 18

1467N2 89/05/04

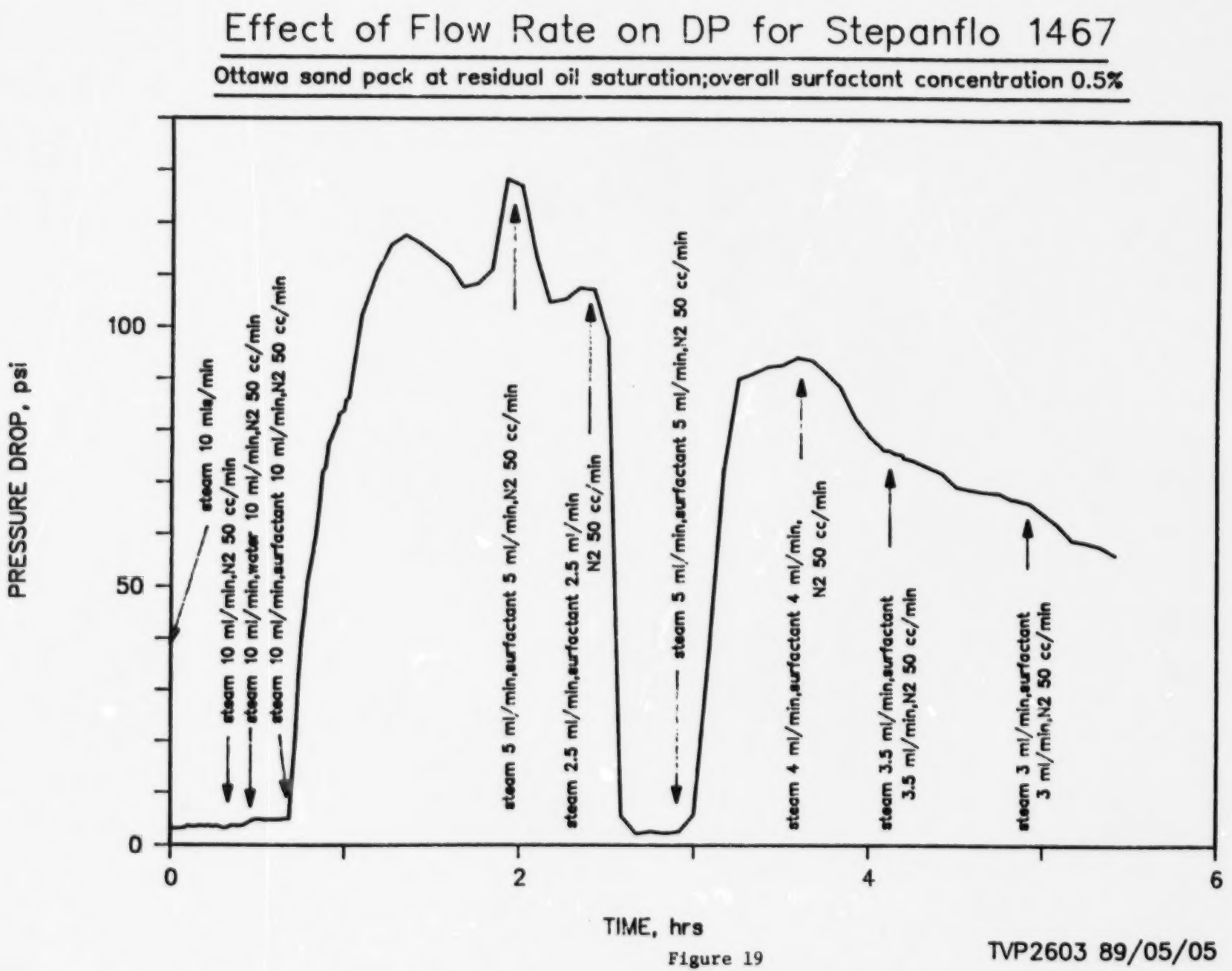

Effect of Flow Rate on DP for Stepanflo 1467
Ottawa sand pack at residual oil saturation;overall surfactant concentration 0.5%
PRESSURE DROP, psi
100
50
0
0
2
4
6
TIME, hrs
steam 10 mls/min
steam 10 ml/min,N2 50 cc/min
steam 10 ml/min,water 10 ml/min,N2 50 cc/min
steam 10 ml/min,surfactant 10 ml/min,N2 50 cc/min
steam 5 ml/min,surfactant 5 ml/min,N2 50 cc/min
steam 2.5 ml/min,surfactant 2.5 ml/min
N2 50 cc/min
steam 5 ml/min,surfactant 5 ml/min,N2 50 cc/min
steam 4 ml/min,surfactant 4 ml/min,
N2 50 cc/min
steam 3.5 ml/min,surfactant
3.5 ml/min,N2 50 cc/min
steam 3 ml/min,surfactant
3 ml/min,N2 50 cc/min
TVP2603 89/05/05

Figure 19

Effect of Flow Rate on DP for Stepanflo 1467

Ottawa sand pack at residual oil saturation;overall surfactant concentration 0.5%

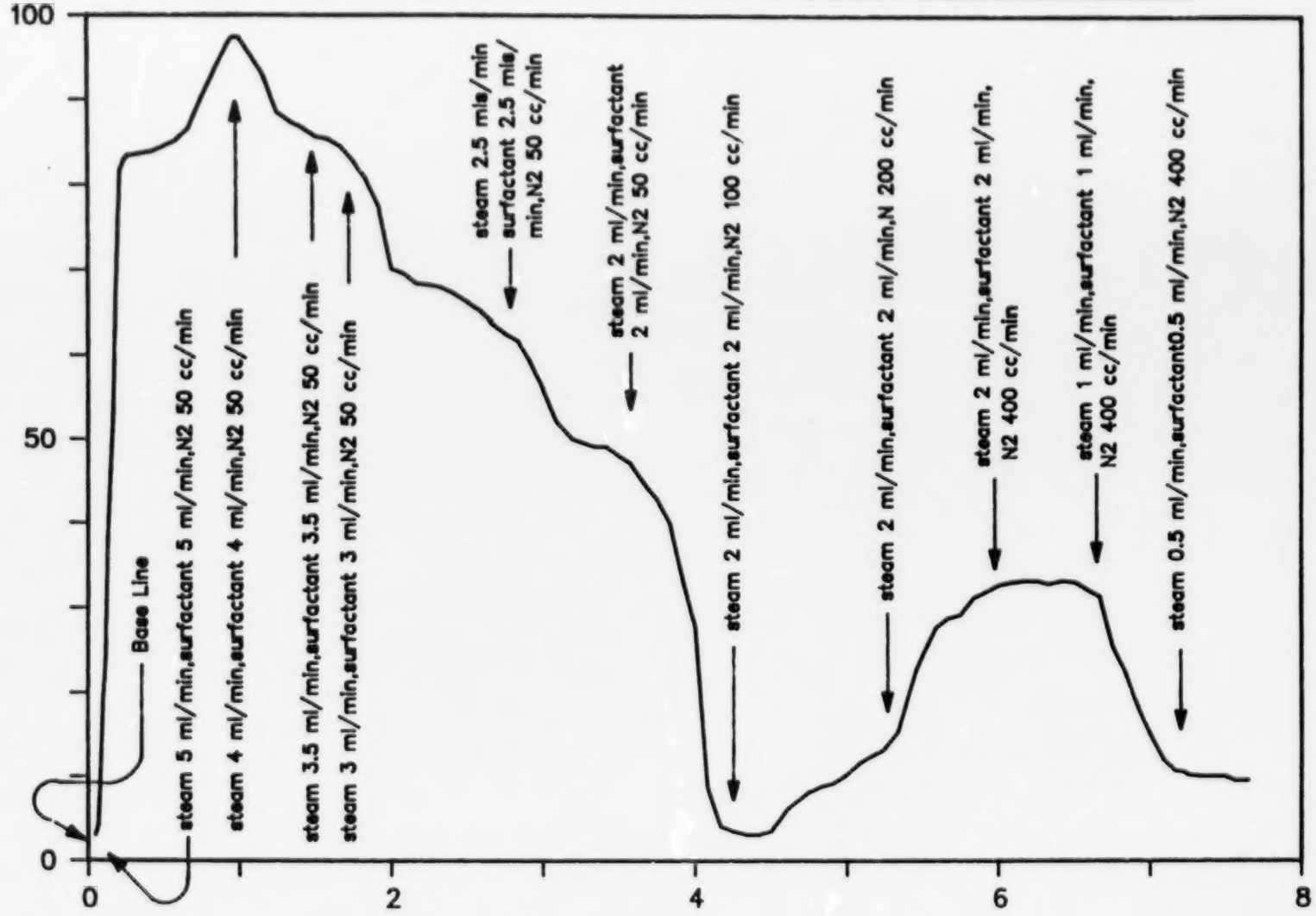

PRESSURE DROP, psi
100
50
0
0
2
4
6
8
TIME, hrs
Base Line
steam 5 ml/min,surfactant 5 ml/min,N2 50 cc/min
steam 4 ml/min,surfactant 4 ml/min,N2 50 cc/min
steam 3.5 ml/min,surfactant 3.5 ml/min,N2 50 cc/min
steam 3 ml/min,surfactant 3 ml/min,N2 50 cc/min
steam 2.5 mls/min surfactant 2.5 mls/ min,N2 50 cc/min
steam 2 ml/min,surfactant 2 ml/min,N2 50 cc/min
steam 2 ml/min,surfactant 2 ml/min,N2 100 cc/min
steam 2 ml/min,surfactant 2 ml/min,N 200 cc/min
steam 2 ml/min,surfactant 2 ml/min, N2 400 cc/min
steam 1 ml/min,surfactant 1 ml/min, N2 400 cc/min
steam 0.5 ml/min,surfactant0.5 ml/min,N2 400 cc/min

Figure 20

TVP2703 89/05/05

Effect of Flow Rate on DP for Stepanflo 1467

Ottawa sand pack at residual oil saturation;overall surfactant concentration 0.5%

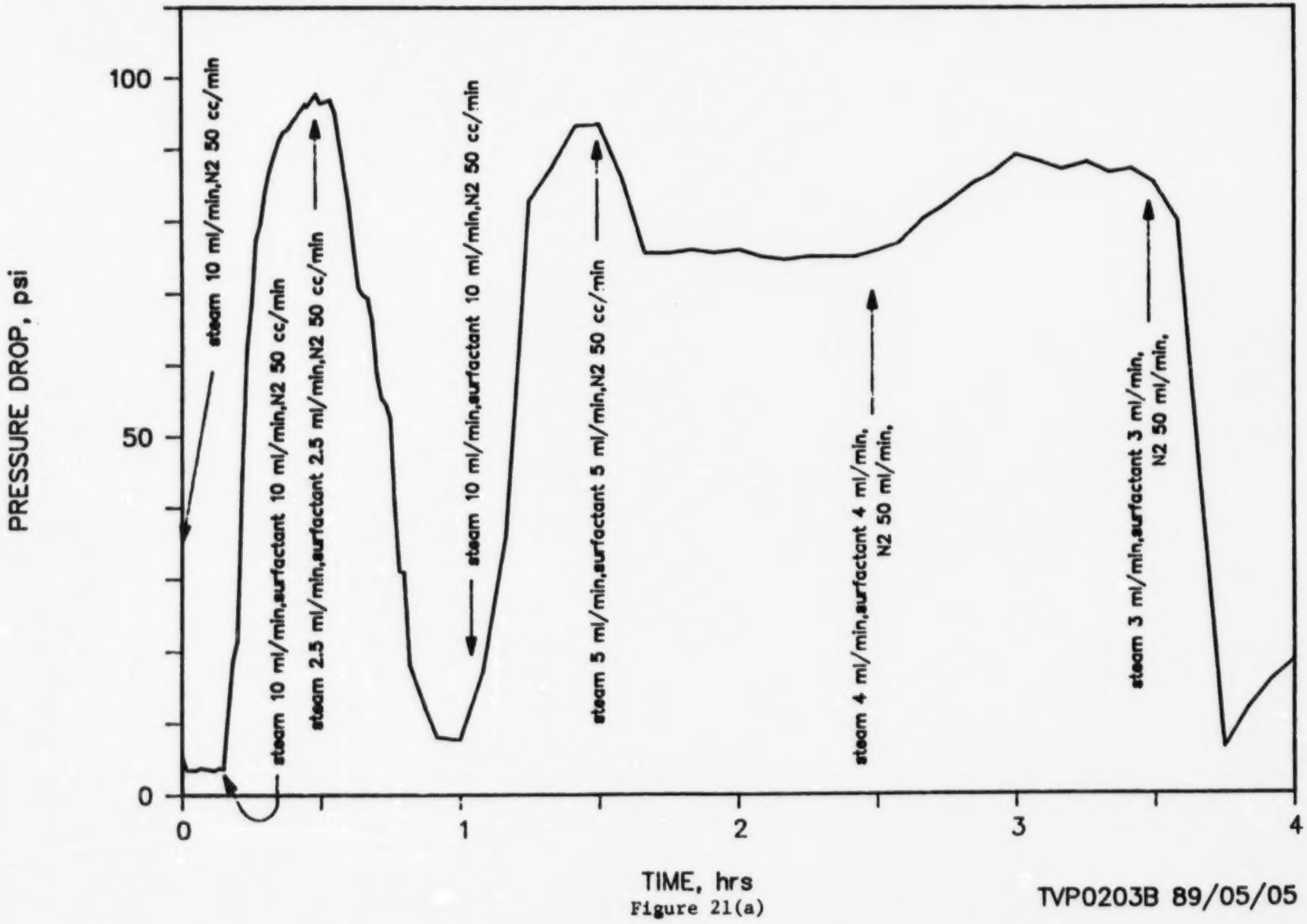


Figure 21(a)

TVP0203B 89/05/05

Effect of Flow Rate on DP for Stepanflo 1467

Ottawa sand pack at residual oil saturation;overall surfactant concentration 0.5%

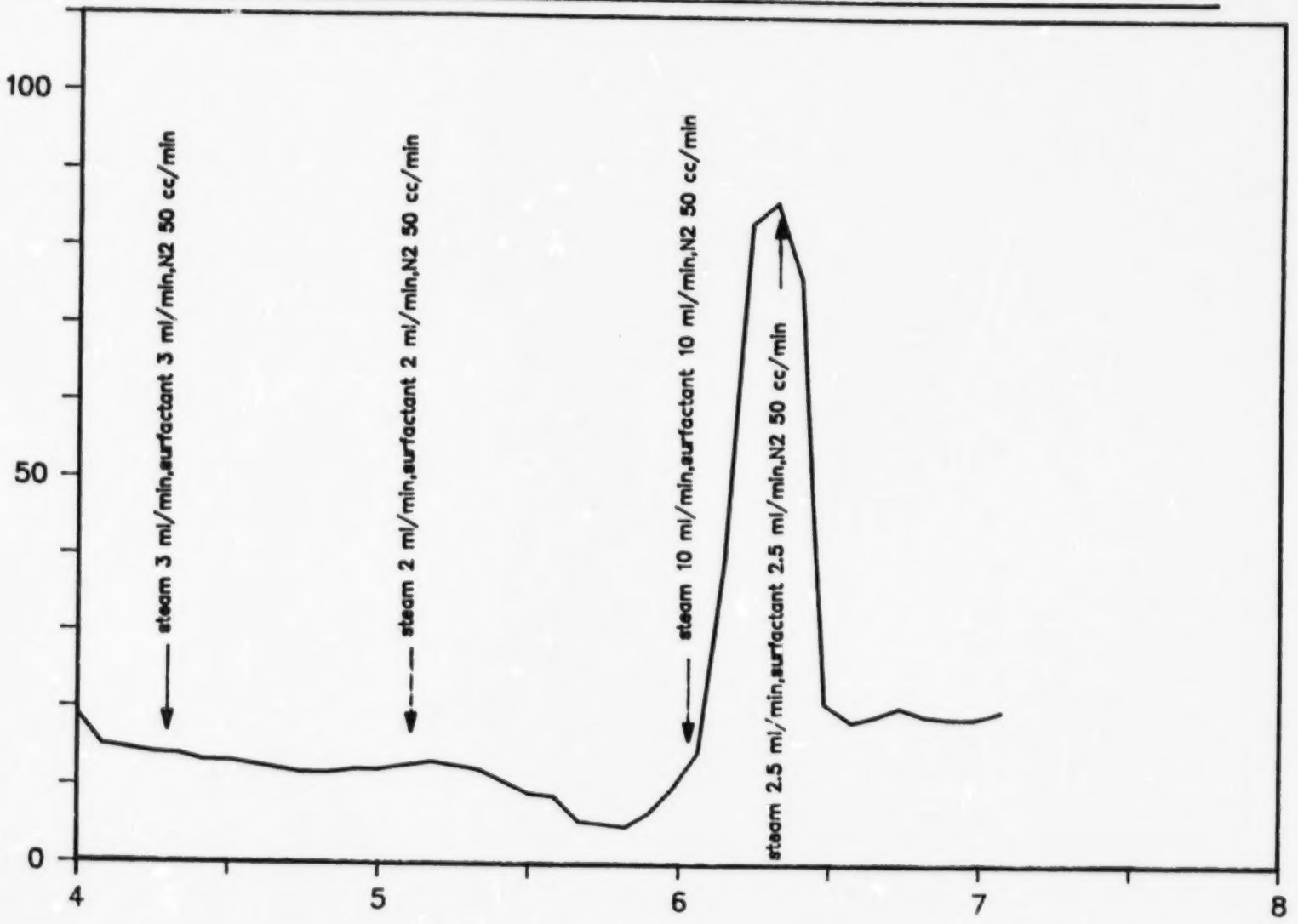


Figure 21(b)

TVP0203C 89/05/05

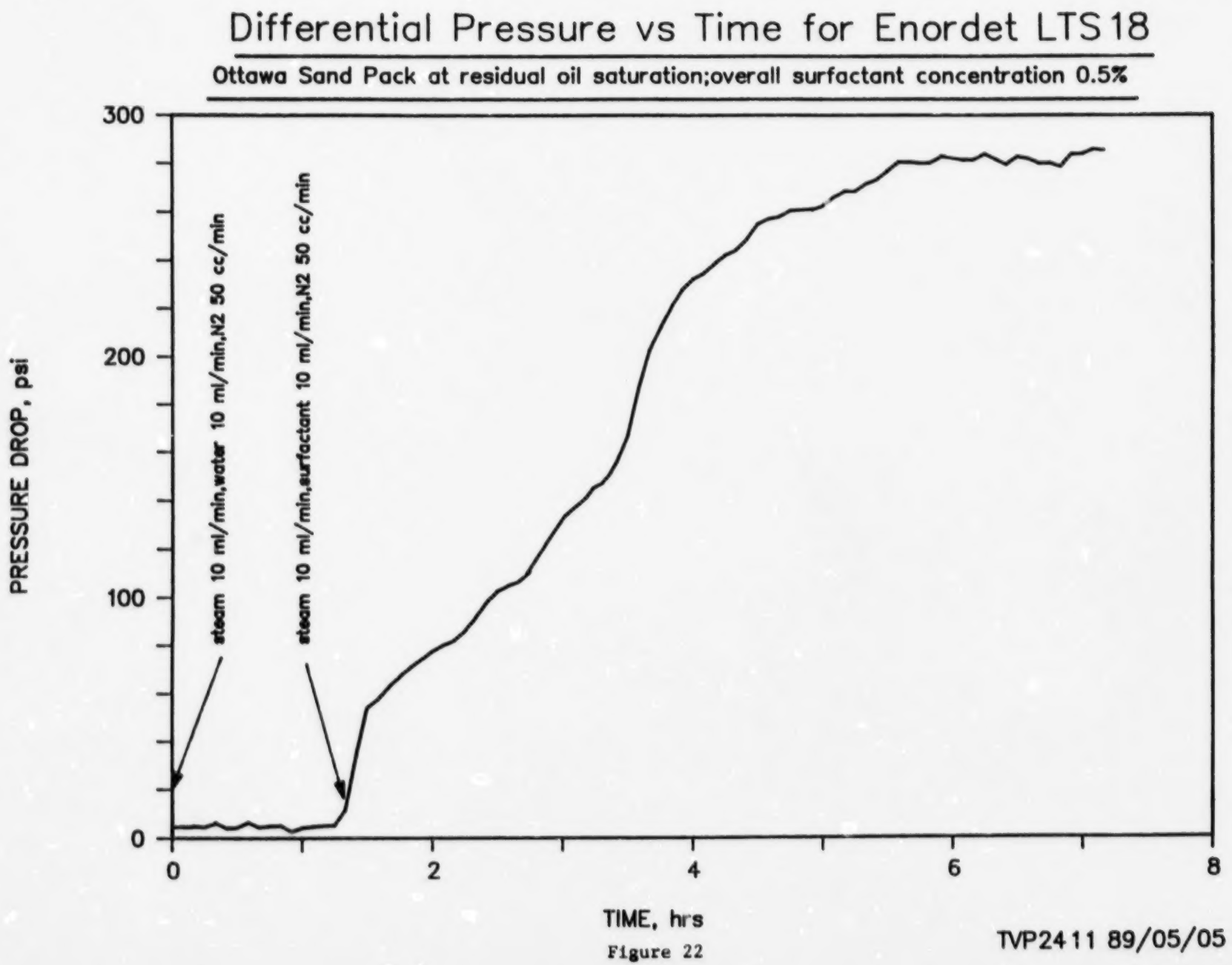

Differential Pressure vs Time for Enordet LTS 18
Ottawa Sand Pack at residual oil saturation;overall surfactant concentration 0.5%
PRESSURE DROP, psi
300
200
100
0
steam 10 ml/min,water 10 ml/min,N2 50 cc/min
steam 10 ml/min,surfactant 10 ml/min,N2 50 cc/min
0
2
4
6
8
TIME, hrs
TVP2411 89/05/05

Figure 22

Effect of Flow Rate on DP for Enordet LTS 18

Ottawa sand pack at residual oil saturation

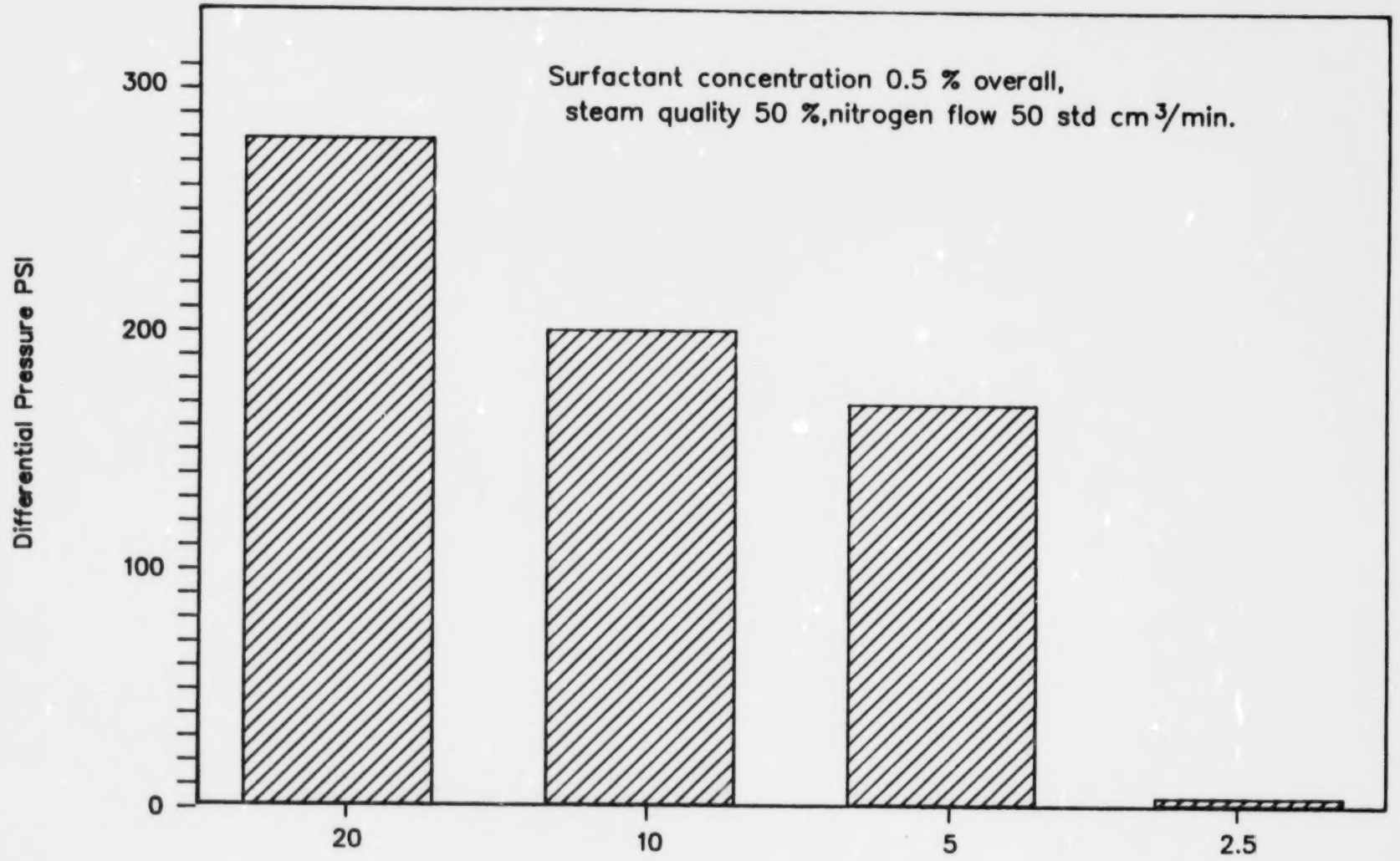


Figure 23

FLLTS 18 89/05/08

Effect of Total Flow Rate & Steam Quality on DP for Suntech IV

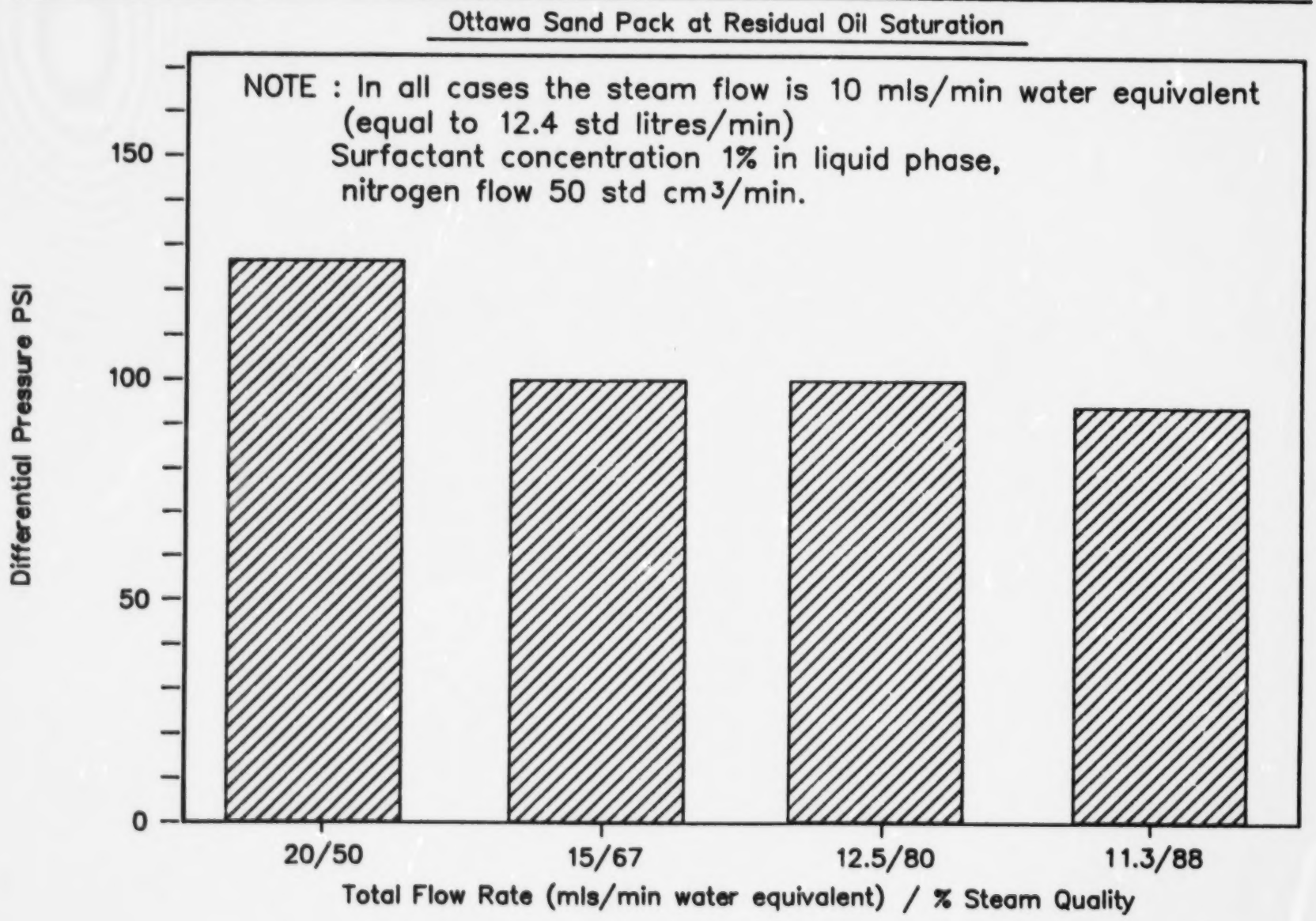

Ottawa Sand Pack at Residual Oil Saturation
NOTE : In all cases the steam flow is 10 mls/min water equivalent (equal to 12.4 std litres/min)
Surfactant concentration 1% in liquid phase,
nitrogen flow 50 std cm3/min.
Differential Pressure PSI
150
100
50
0
20/50
15/67
12.5/80
11.3/88
Total Flow Rate (mls/min water equivalent) / % Steam Quality

Figure 24

Effect of Flow Rate & Concentration on DP for Suntech IV

Ottawa Sand Pack at Residual Oil Saturation

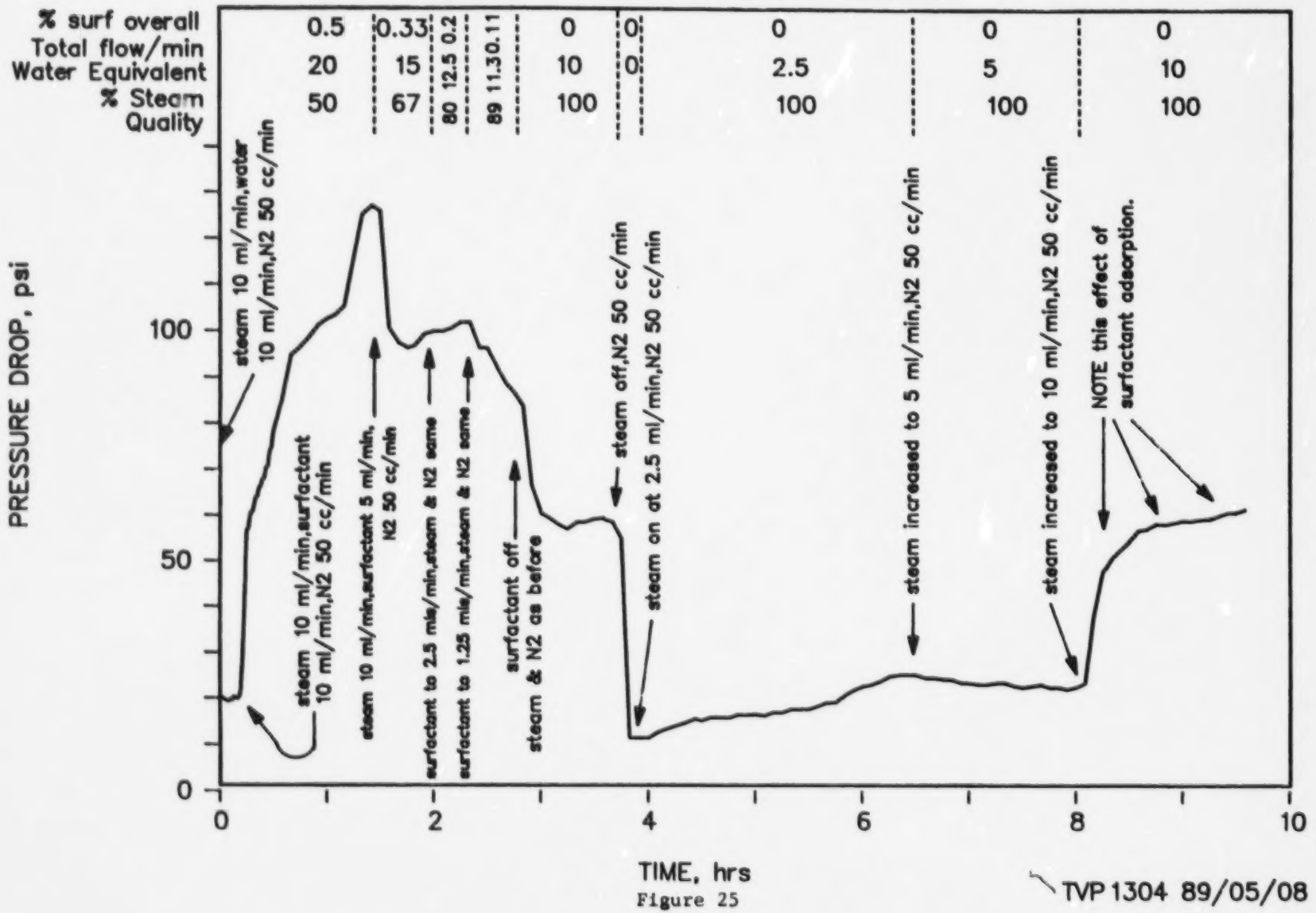


Figure 25

TVP 1304 89/05/08

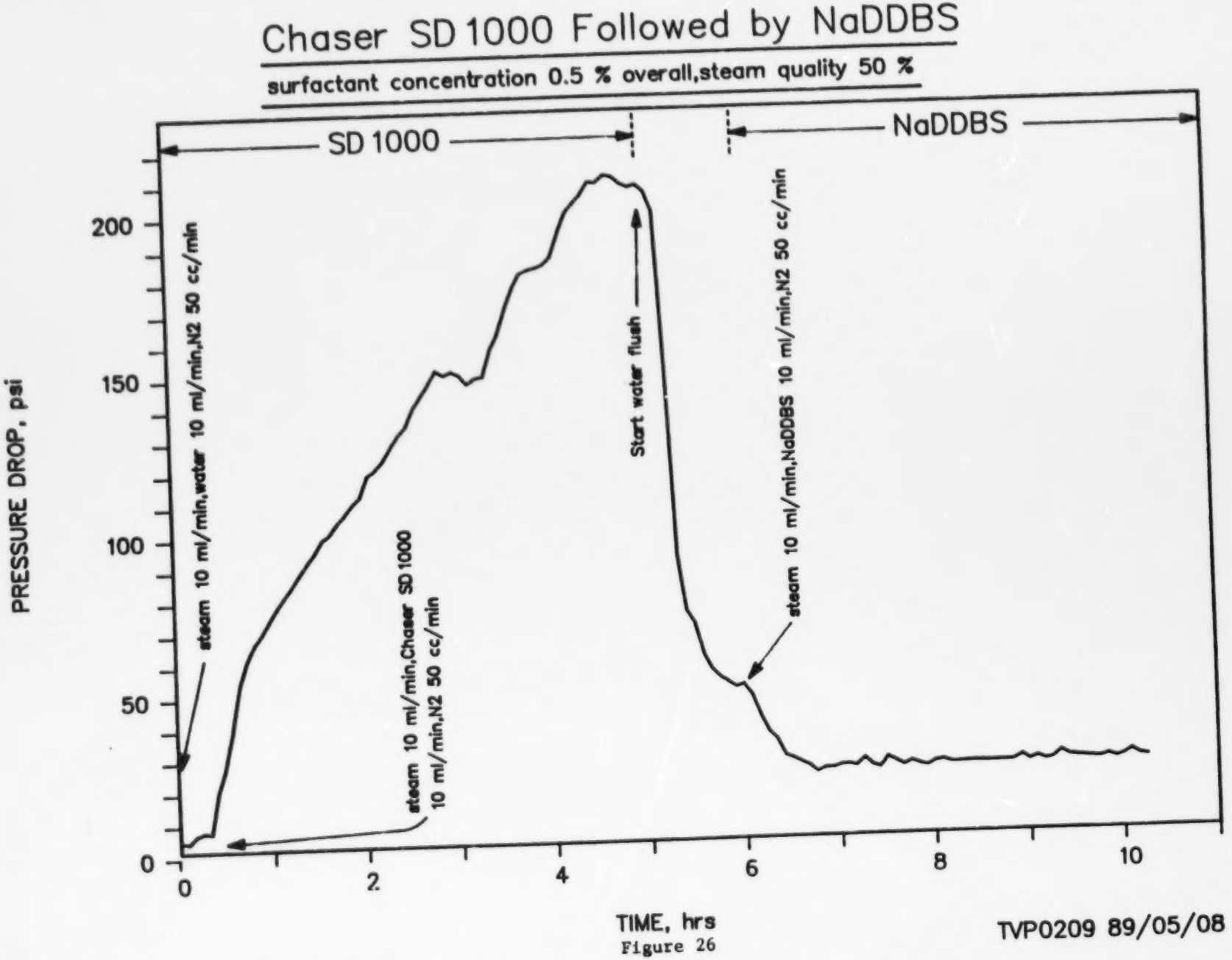

Chaser SD 1000 Followed by NaDDBS
surfactant concentration 0.5 % overall,steam quality 50 %
SD 1000
NaDDBS
PRESSURE DROP, psi
200
150
100
50
0
0
2
4
6
8
10
TIME, hrs
steam 10 ml/min,water 10 ml/min,N2 50 cc/min
steam 10 ml/min,Chaser SD 1000
10 ml/min,N2 50 cc/min
Start water flush
steam 10 ml/min,NaDDBS 10 ml/min,N2 50 cc/min
TVP0209 89/05/08

Figure 26

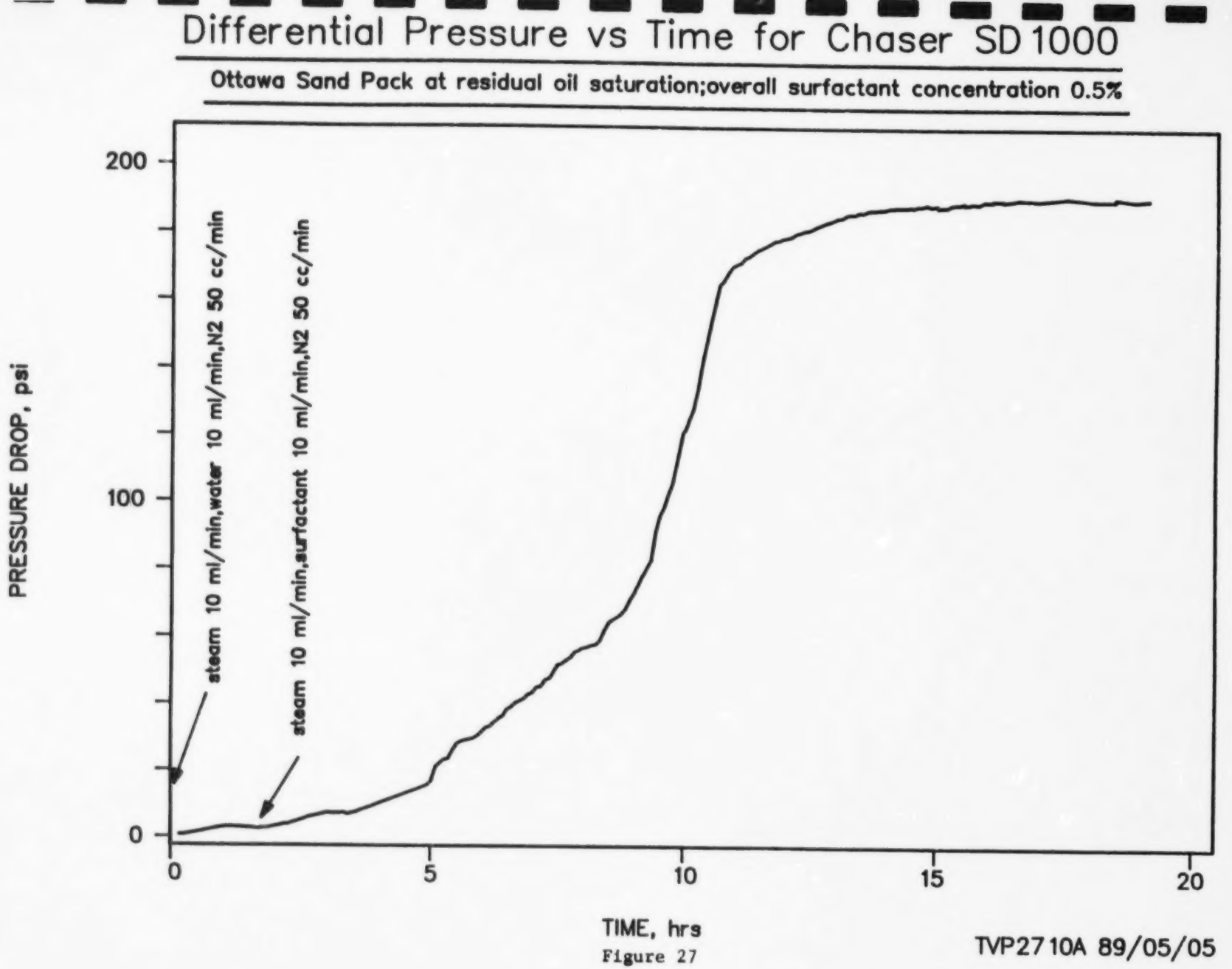

Differential Pressure vs Time for Chaser SD 1000
Ottawa Sand Pack at residual oil saturation;overall surfactant concentration 0.5%
PRESSURE DROP, psi
200
100
0
steam 10 ml/min,water 10 ml/min,N2 50 cc/min
steam 10 ml/min,surfactant 10 ml/min,N2 50 cc/min
0
5
10
15
20
TIME, hrs
TVP2710A 89/05/05

Figure 27

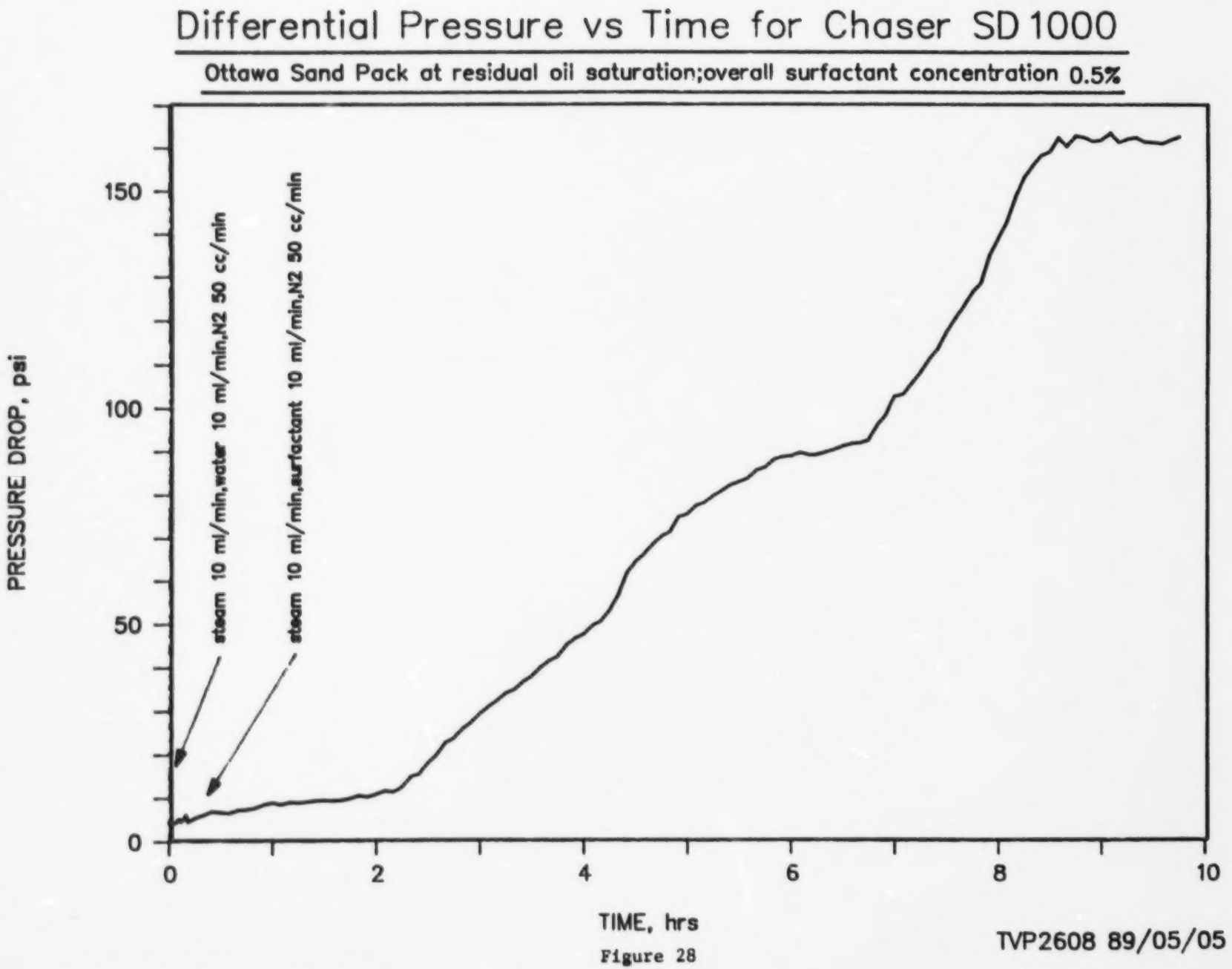

Differential Pressure vs Time for Chaser SD 1000
Ottawa Sand Pack at residual oil saturation;overall surfactant concentration 0.5%
PRESSURE DROP, psi
150
100
50
0
steam 10 ml/min,water 10 ml/min,N2 50 cc/min
steam 10 ml/min,surfactant 10 ml/min,N2 50 cc/min
0
2
4
6
8
10
TIME, hrs
TVP2608 89/05/05

Figure 28

Reproducibility of Results for Chaser SD 1000

Ottawa Sand Pack at residual oil saturation;overall surfactant concentration 0.5%

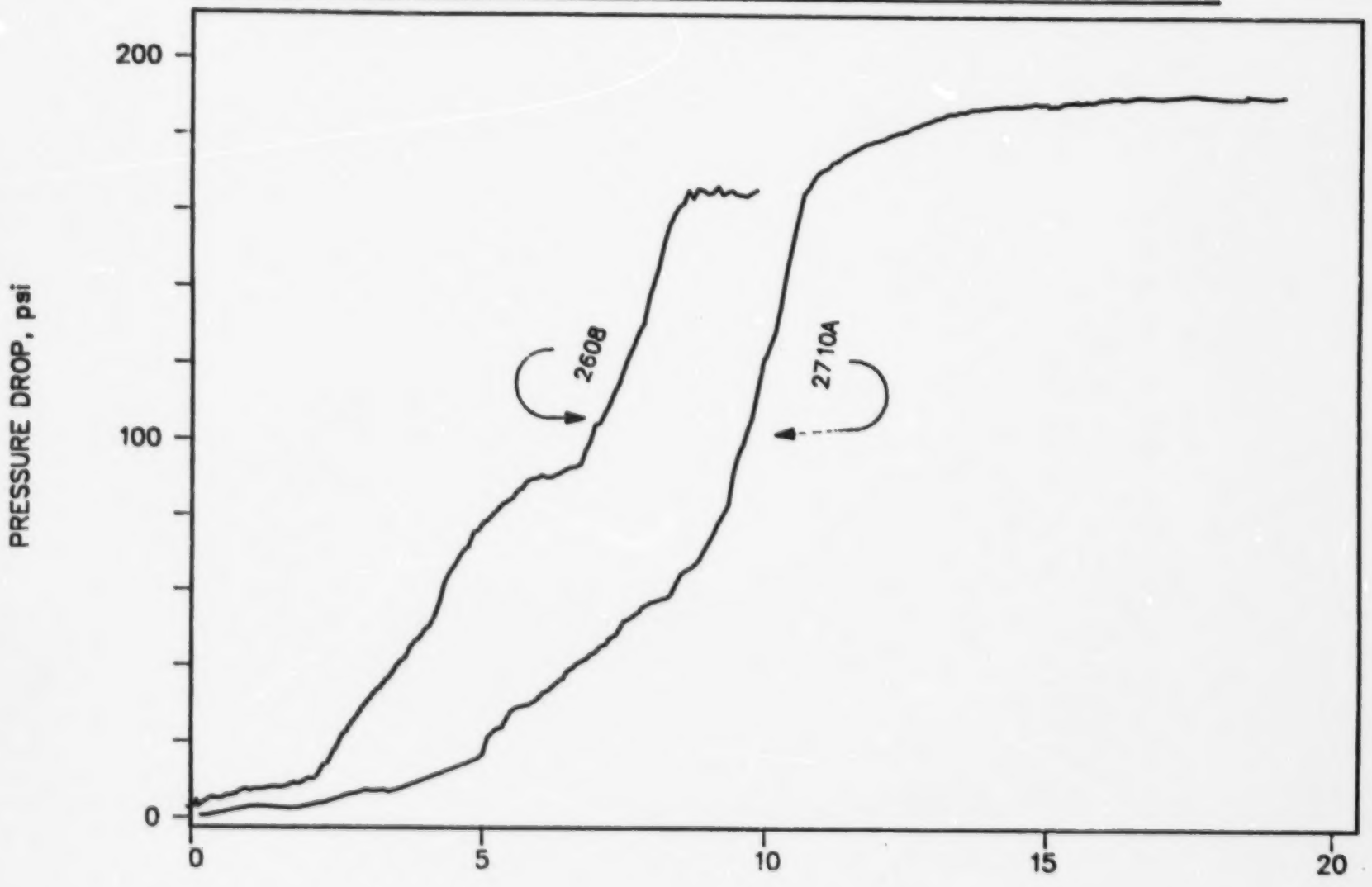


Figure 29

COMPSD 89/05/08

Effect of Flow Rate on DP for Chaser SD 1000

Ottawa Sand Pack at Residual Oil Saturation

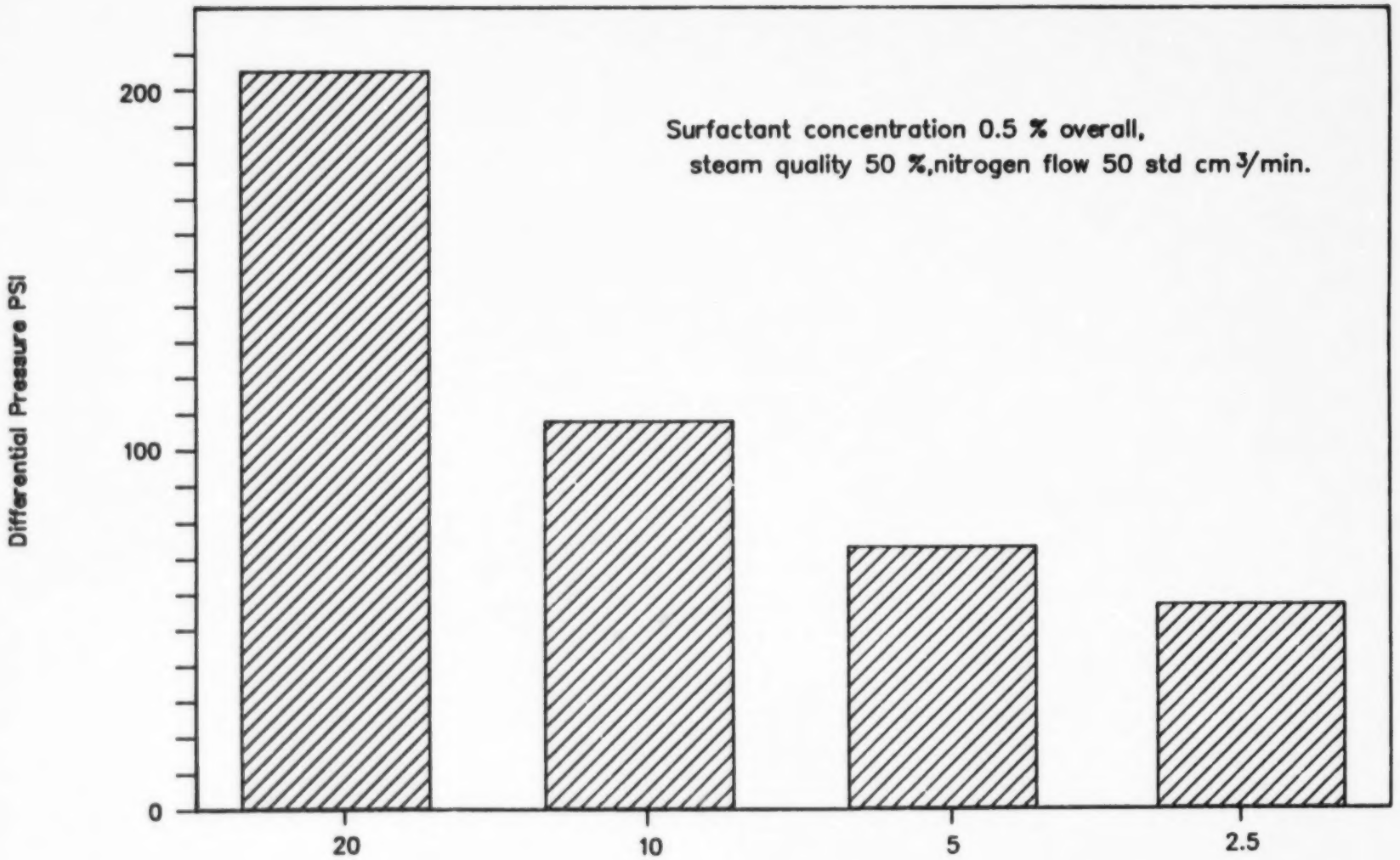


Figure 30

FISD87 89/05/03

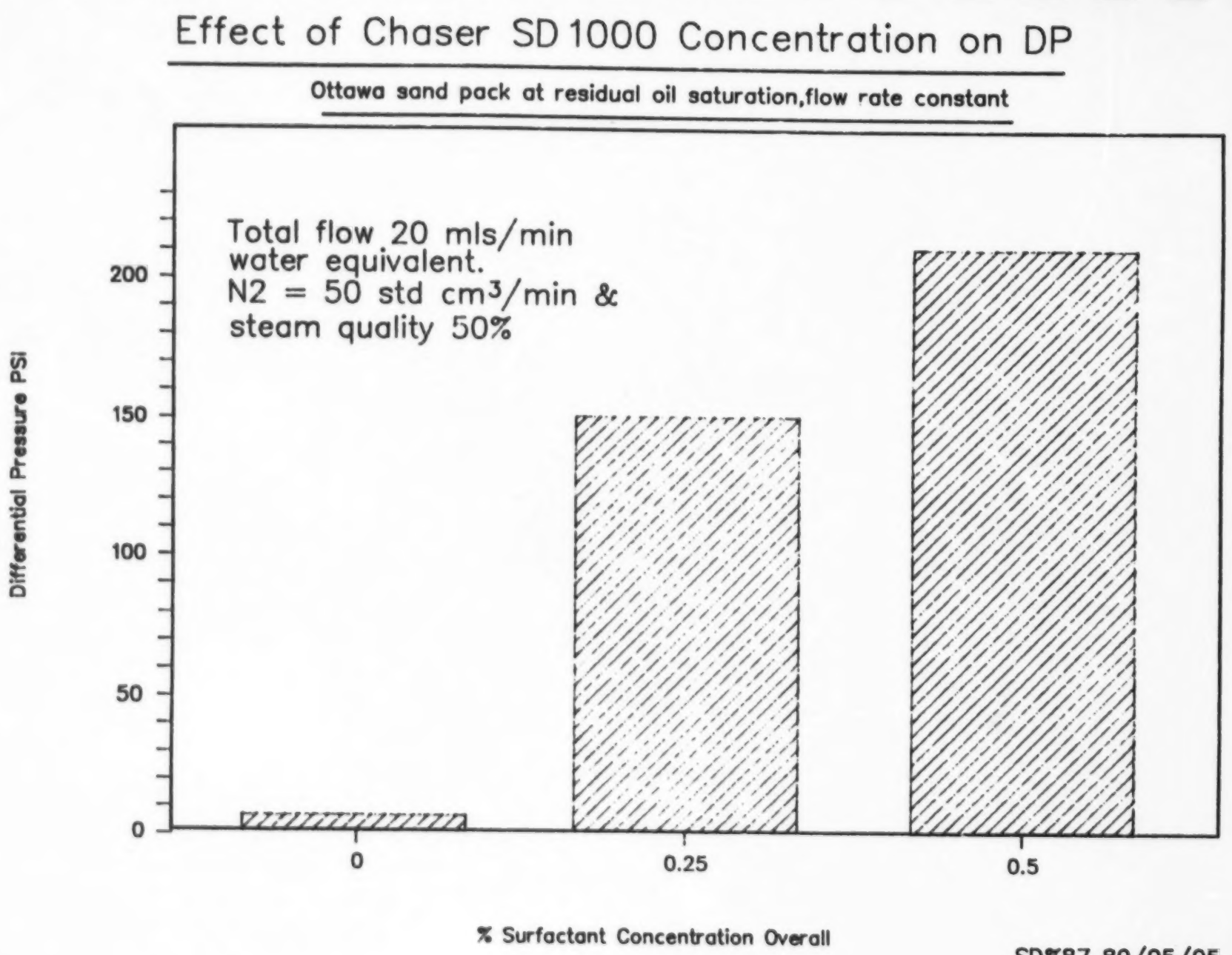
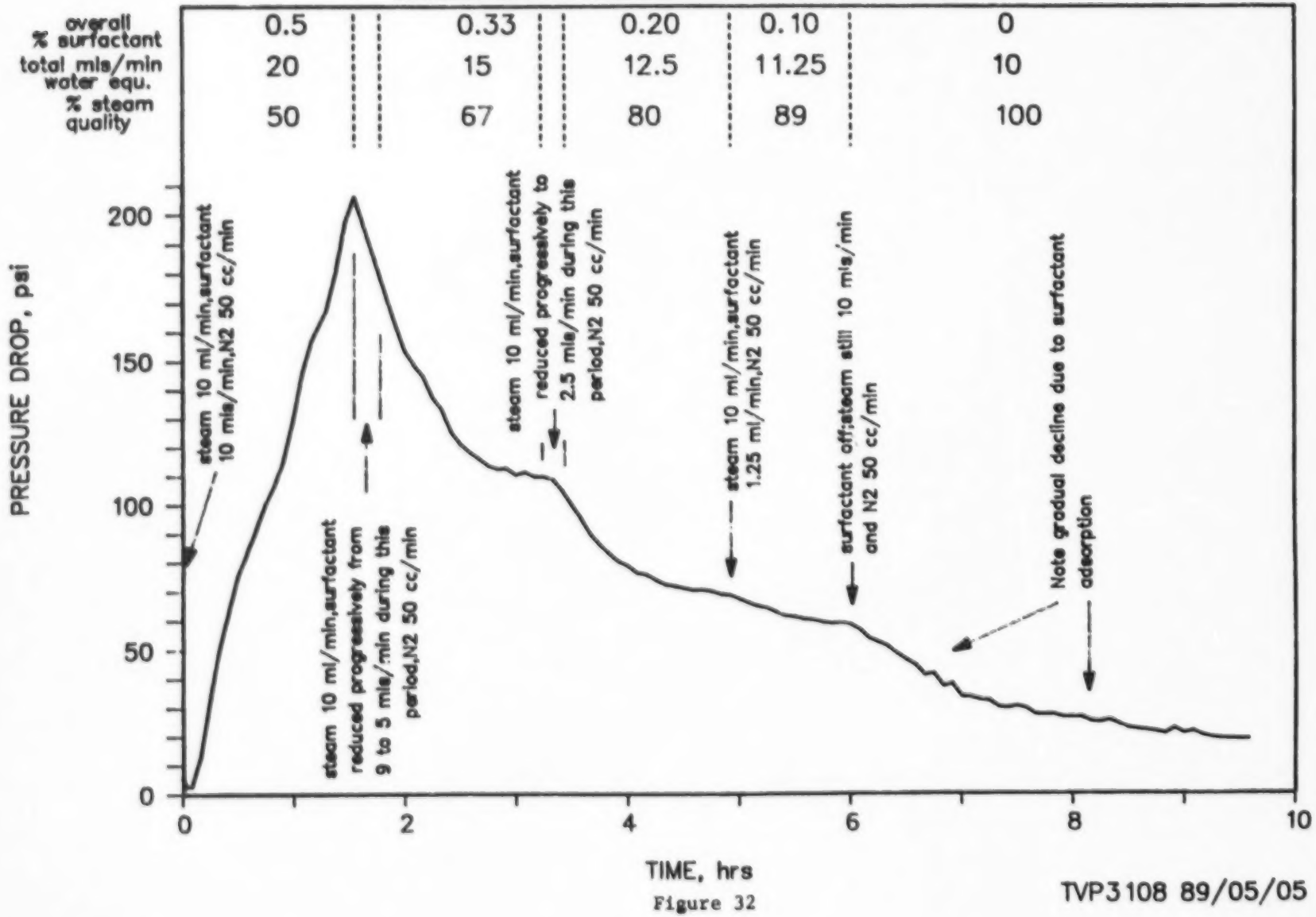

Effect of Chaser SD 1000 Concentration on DP
Ottawa sand pack at residual oil saturation,flow rate constant
Total flow 20 mls/min
water equivalent.
N2 = 50 std cm3/min &
steam quality 50%
Differential Pressure PSI
200
150
100
50
0
0
0.25
0.5
% Surfactant Concentration Overall
SD%87 89/05/05

Figure 31

Effect of Flow Rate & Concentration on DP for Chaser SD 1000

Ottawa Sand Pack at Residual Oil Saturation



TVP3108 89/05/05

Figure 32

Effect of N2 Flow Rate on DP for Chaser SD 1000

Ottawa sand pack at residual oil saturation

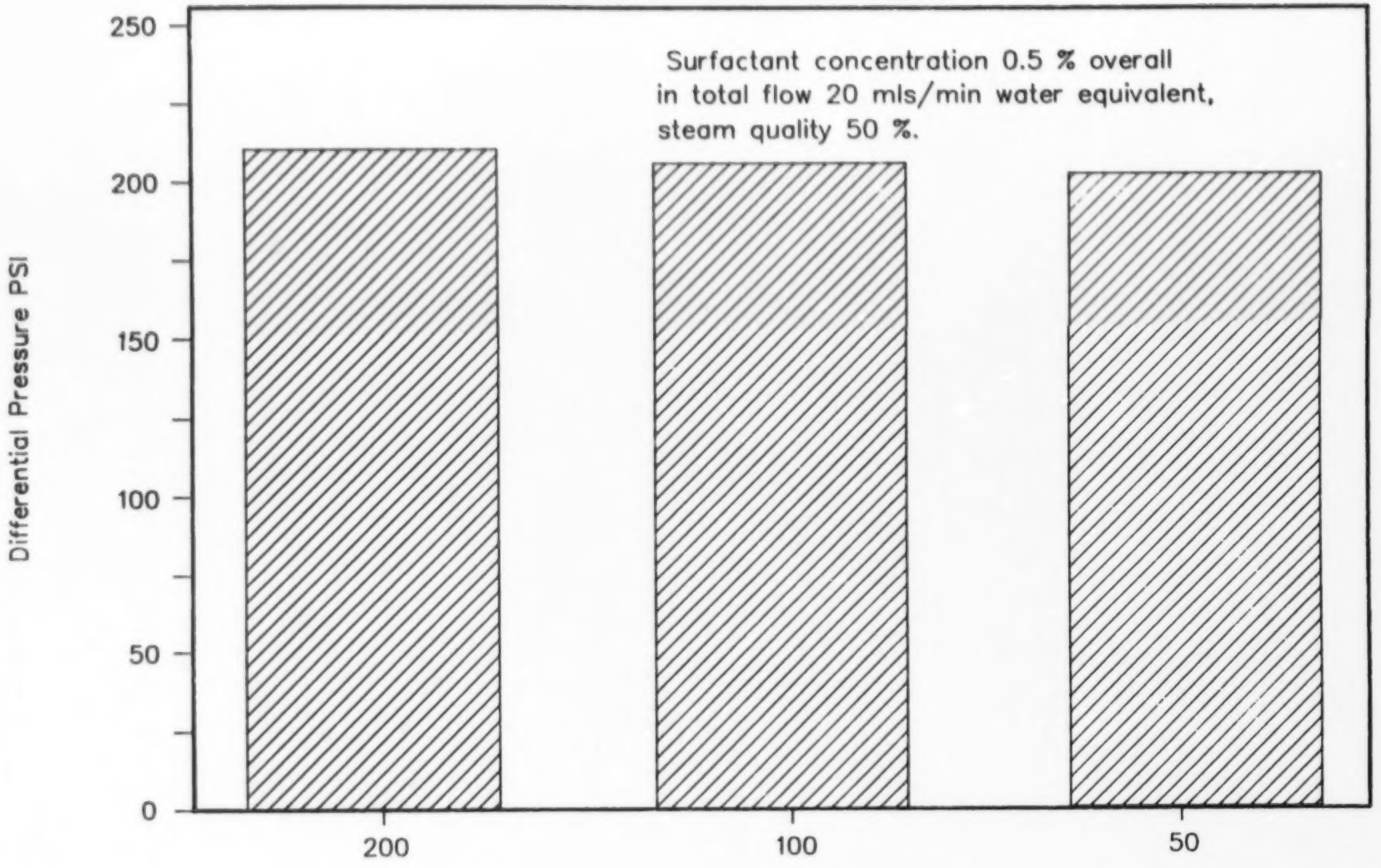
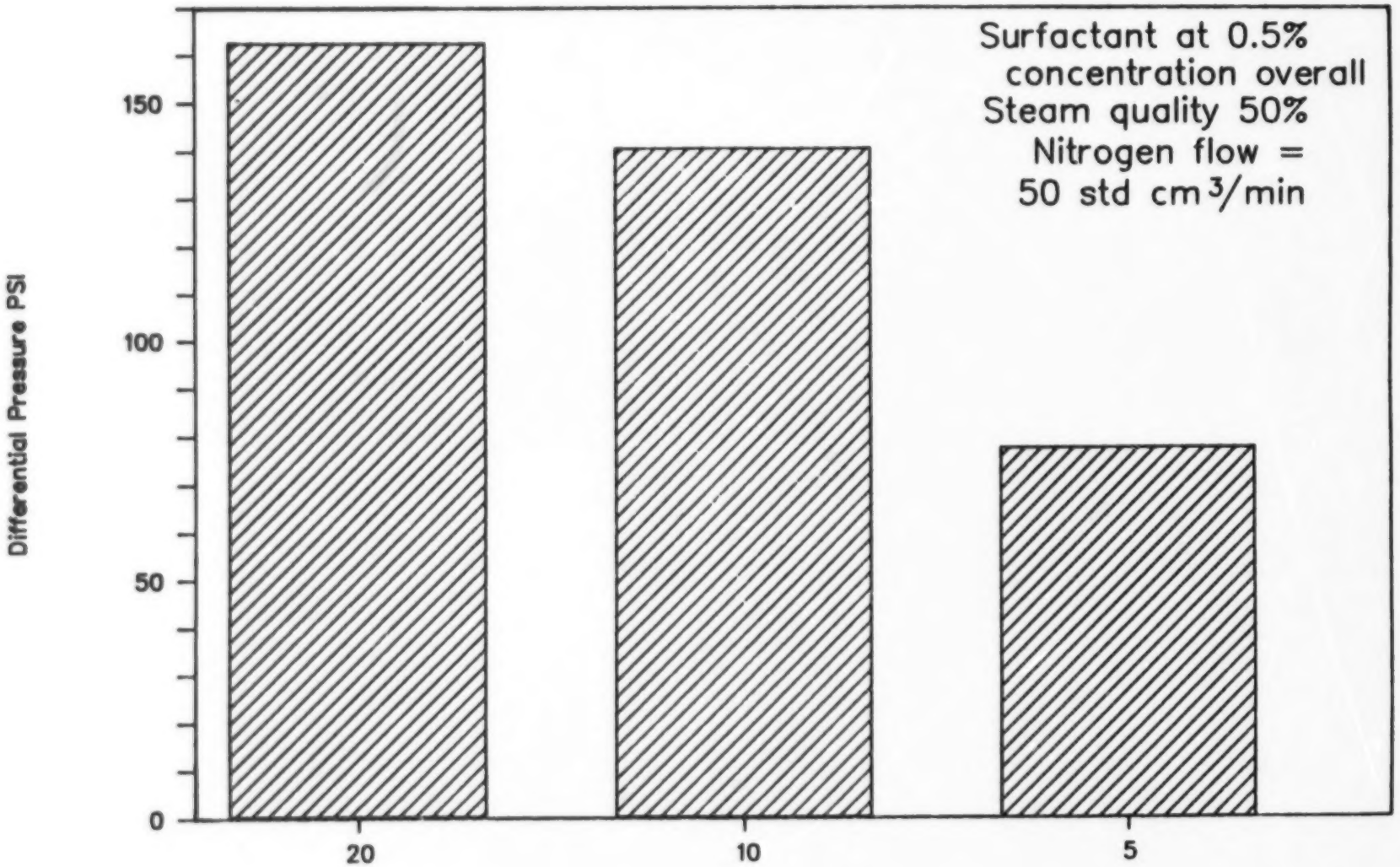


Figure 33

SDVN2 89/05/05

Effect of Flow Rate on DP for Chaser SD 1000

Frog Lake core at residual oil saturation



FLSURFF 89/05/04

Figure 34

Effect of Chaser XP2416 Concentration on DP

Frog Lake core at residual oil saturation, flow rate constant.

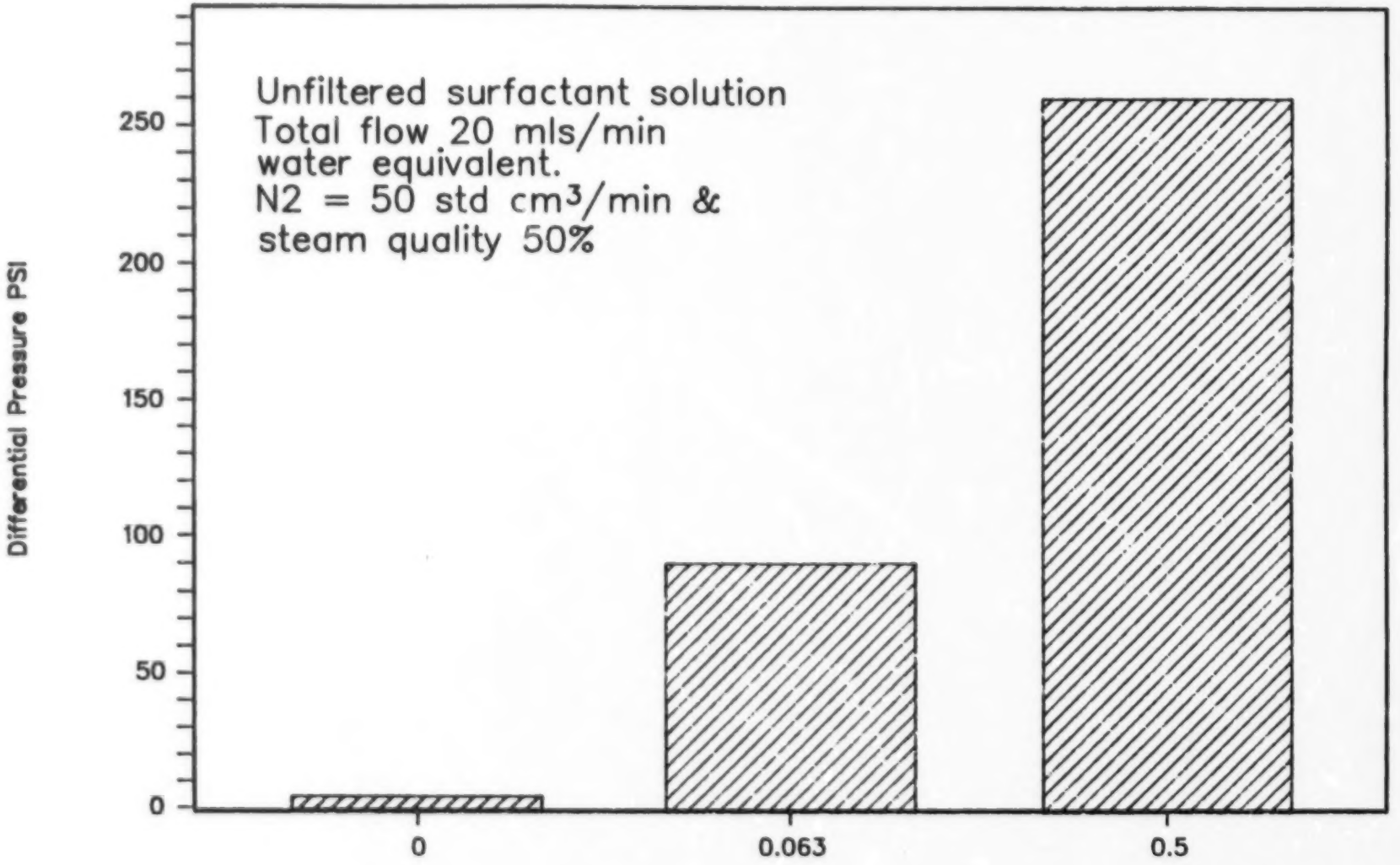


Figure 35

XP%88 89/05/03

Effect of Flow Rate on DP for Chaser XP2416

Frog Lake core at residual oil saturation

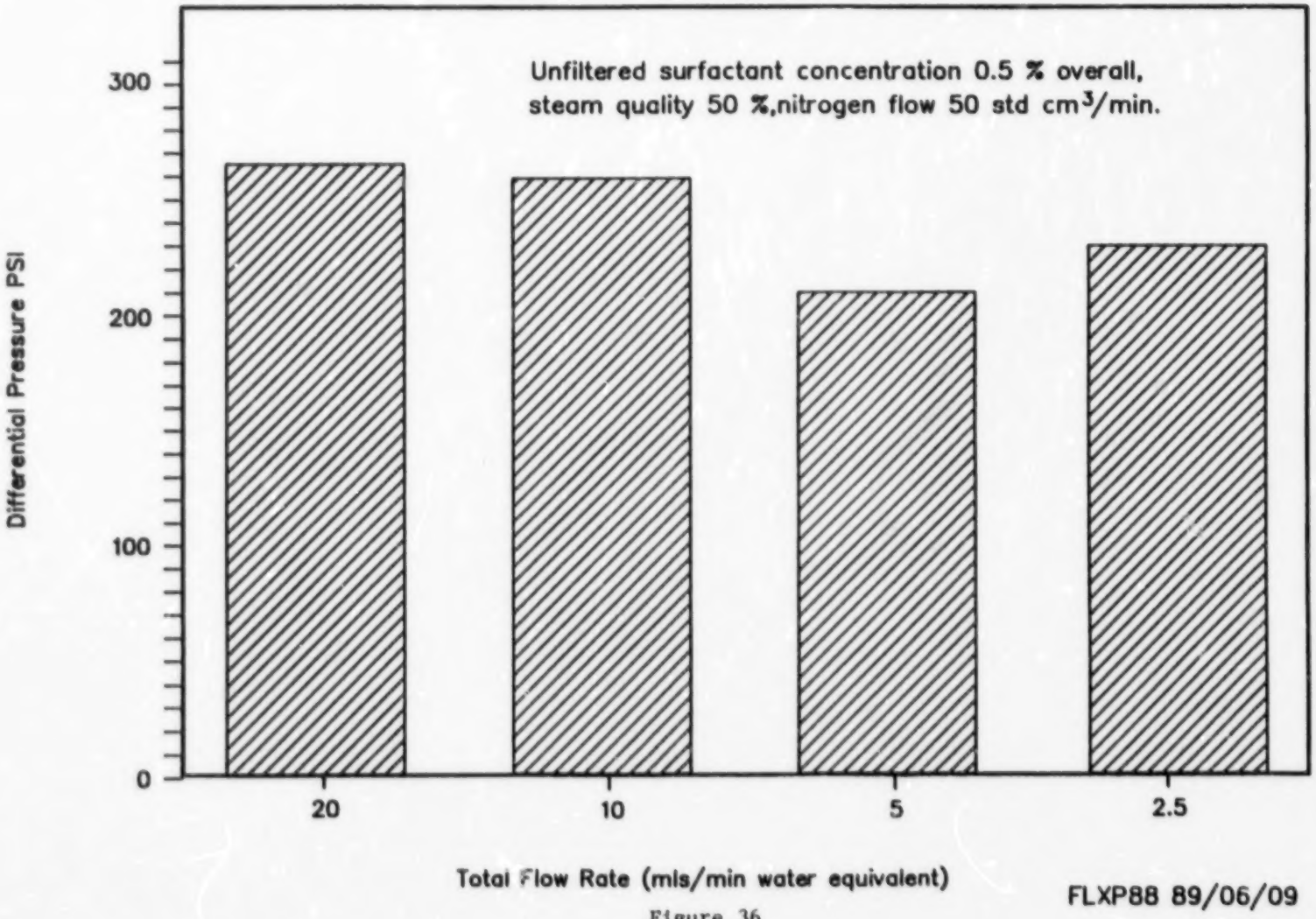


Figure 36

Effect of Surfactant Pre-Filtration on DP

Frog Lake core at residual oil saturation

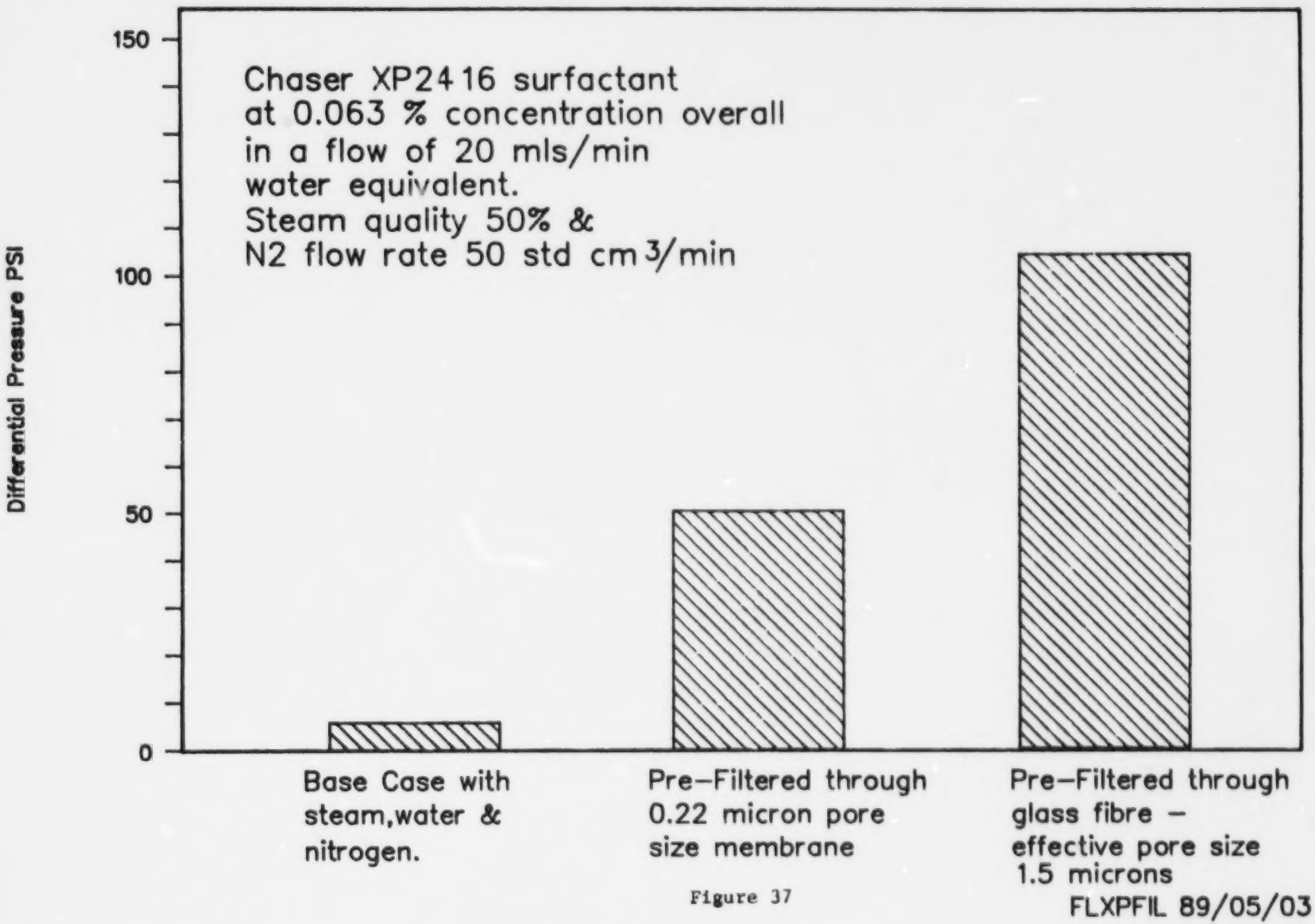
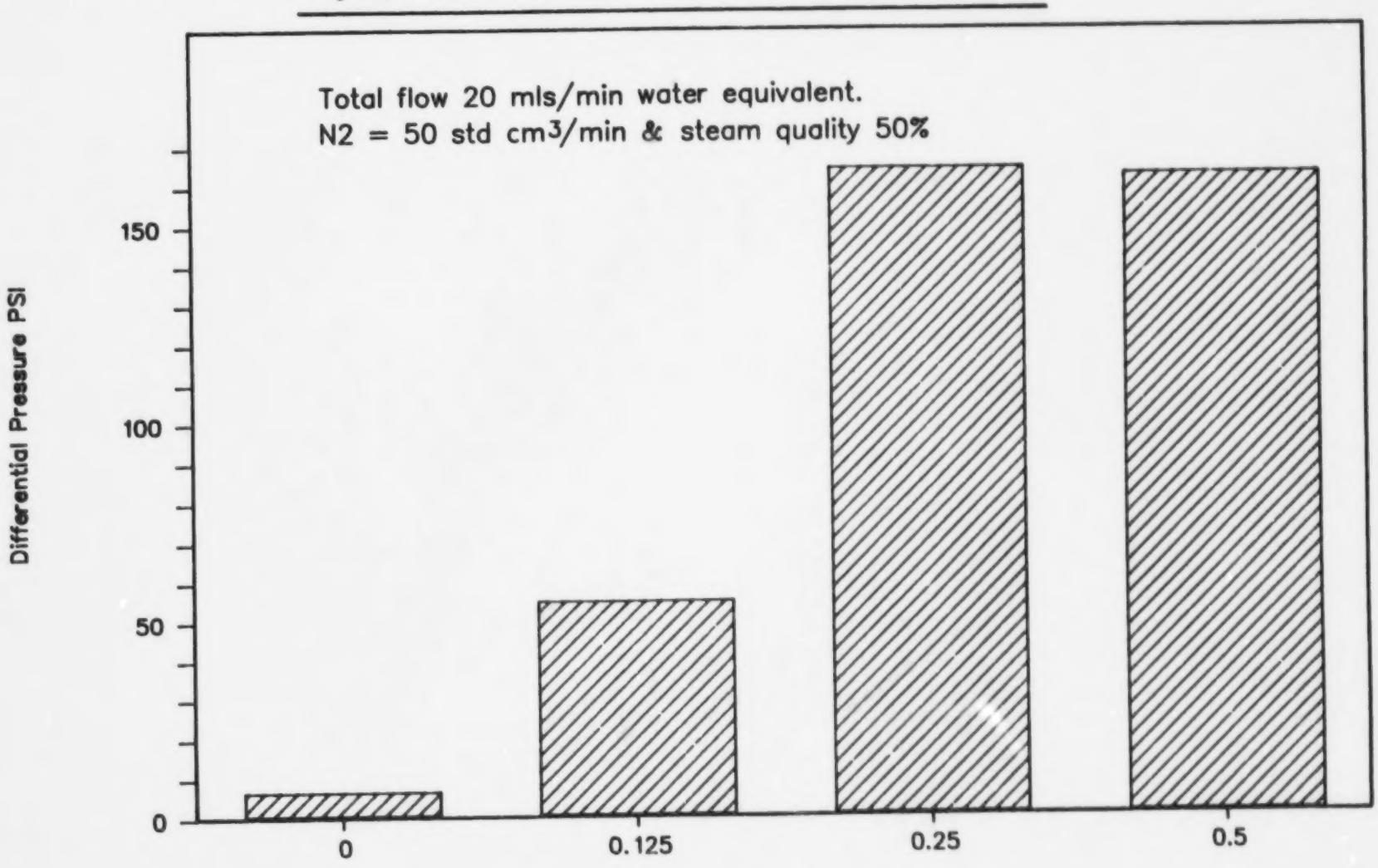

Differential Pressure PSI
150
100
50
0
Chaser XP2416 surfactant
at 0.063 % concentration overall
in a flow of 20 mls/min
water equivalent.
Steam quality 50% &
N2 flow rate 50 std cm3/min
Base Case with steam,water & nitrogen.
Pre-Filtered through 0.22 micron pore size membrane
Pre-Filtered through glass fibre - effective pore size 1.5 microns

Figure 37

FLXPFIL 89/05/03

Effect of Chaser SD 1000 Concentration on DP

Frog Lake core at residual oil saturation, flow rate constant.



FL%SURF 89/05/03

Figure 38

Effect of Varying Steam Quality on DP in Absence of Non-Condensible Gas

Frog Lake core at residual oil saturation

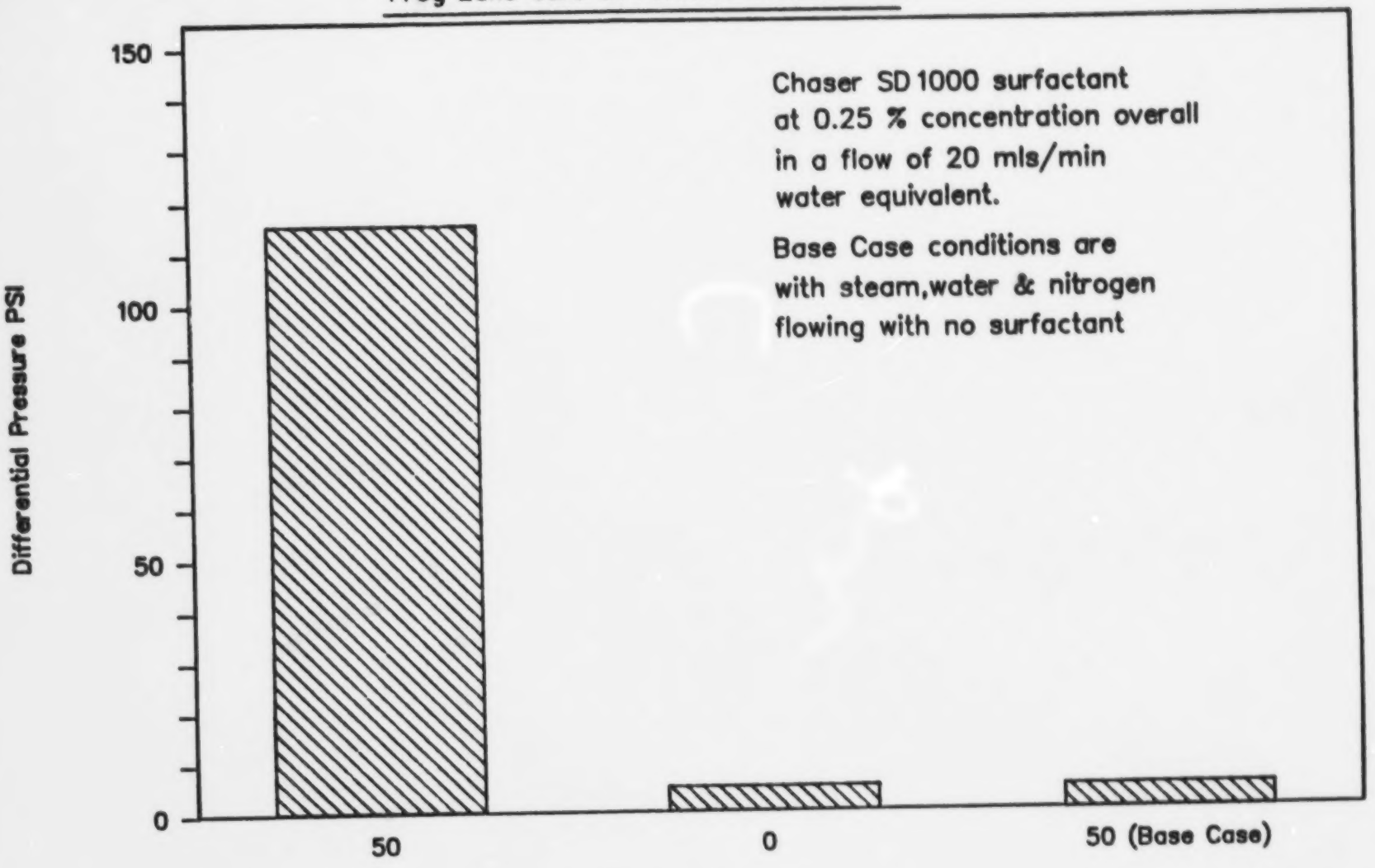


Figure 39

FLSVN20 89/05/05

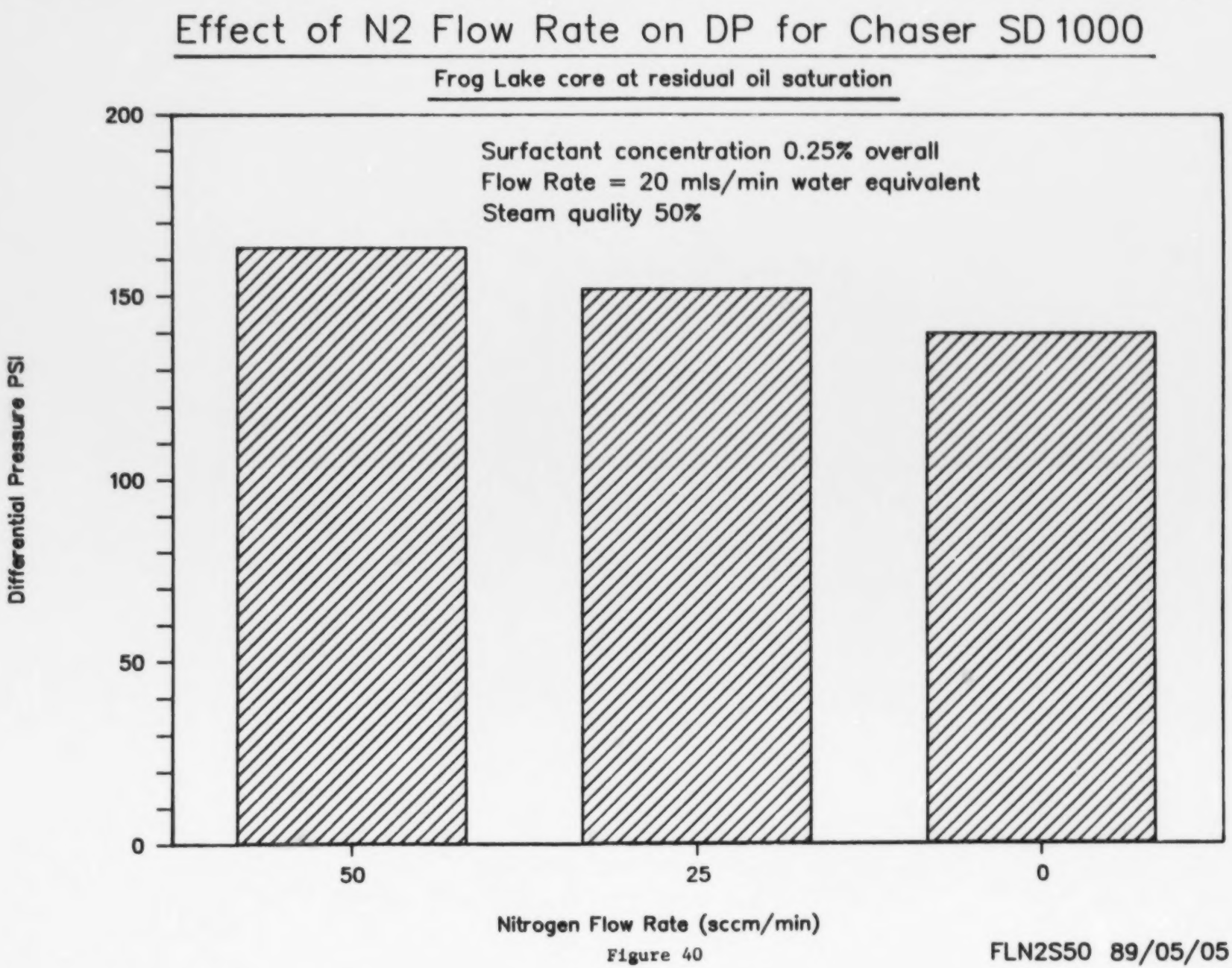

Effect of N2 Flow Rate on DP for Chaser SD 1000
Frog Lake core at residual oil saturation
Surfactant concentration 0.25% overall
Flow Rate = 20 mls/min water equivalent
Steam quality 50%
Differential Pressure PSI
200
150
100
50
0
50
25
0
Nitrogen Flow Rate (sccm/min)
FLN2S50 89/05/05

Figure 40

Schematic of Field Foam Injection Facilities

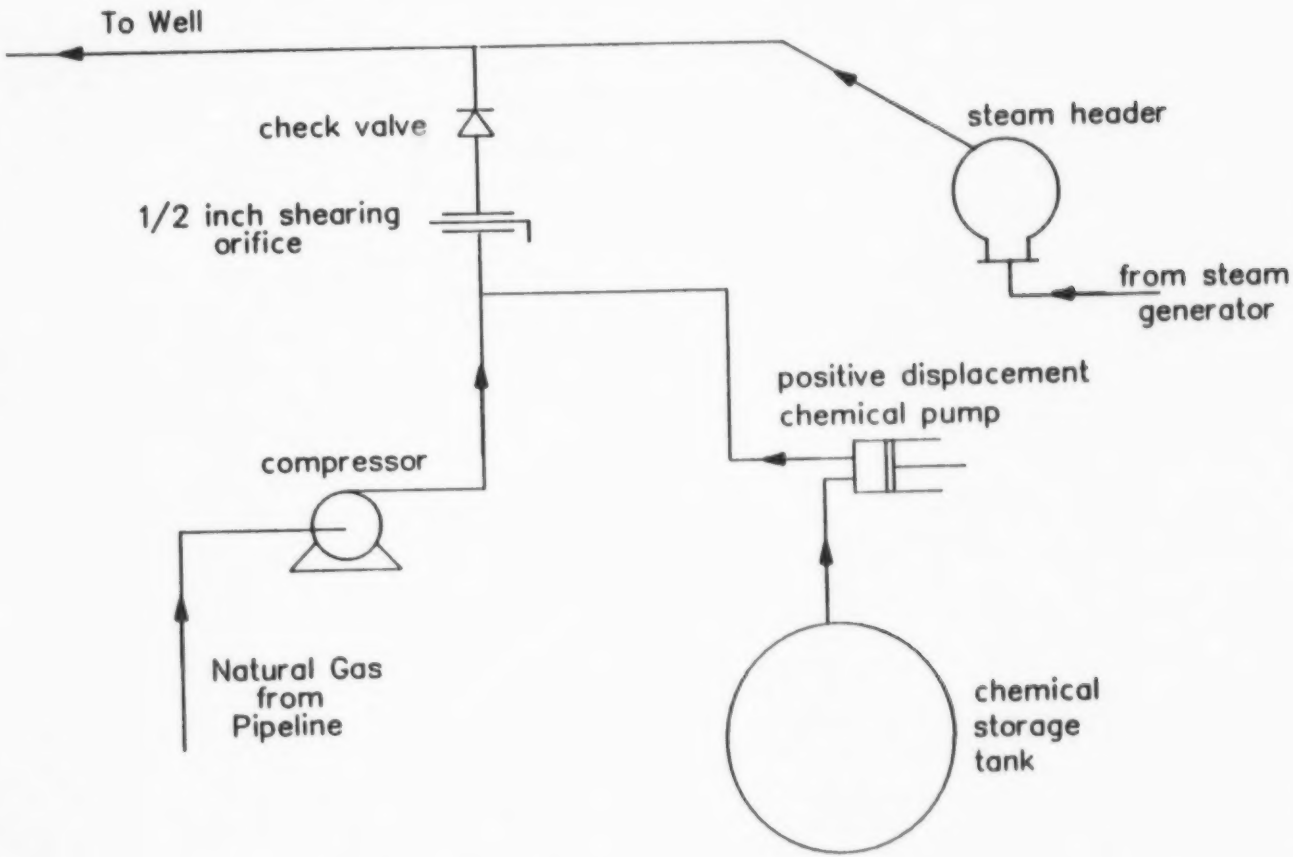


Figure 41

Field 89/06/06